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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE
AND THE DELAWARE ENERGY OFFICE

IN THE MATTER OF INTEGRATED RESOURCE PLANNING FOR THE PROVISION OF STANDARD OFFER SERVICE BY DP&L POWER & LIGHT COMPANY UNDER 26 *DEL. C.* §1007(c) & (d): REVIEW AND APPROVAL OF THE REQUEST FOR PROPOSALS FOR THE CONSTRUCTION OF NEW GENERATION RESOURCES UNDER 26 *DEL. C.* §1007(d) (Opened July 25, 2006)	**))))))))**	**PSC DOCKET NO. 06-241**

FINAL FINDINGS, OPINION AND ORDER NO. _______

BEFORE:

ARNETTA McRAE, Chair
JAYMES B. LESTER, Commissioner
JOANN T. CONAWAY, Commissioner
J. DALLAS WINSLOW, Commissioner
JEFFREY J. CLARK, Commissioner

and

PHILIP J. CHERRY, Director of Policy & Planning
Delaware Department of Natural Resources and
Environmental Control, Delaware Energy Office

APPEARANCES:

For the Staff of the Delaware Public Service Commission ("Staff"):

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Rate Counsel

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I. THE STATUTORY BACKGROUND

1. Pursuant to the Electric Utility Restructuring Act of 1999, 26 *Del. C.* ch. 10, upon the expiration of the applicable "transition period," retail customers in DP&L Power & Light Company's ("DP&L") service territory who do not otherwise receive electric service from an electric supplier will be provided "standard offer service" ("SOS") by the "standard offer service supplier." *See* 26 *Del. C.* §§1001(18); 1006(a)(2)a.-c.

2. The transition period for all customer classes in DP&L's service territory ended in September 2003. As part of the resolution of DP&L's merger into the Pepco Holdings, Inc. family, the Delaware Public Service Commission (the "Commission") accepted DP&L's offer to serve as the SOS supplier for its service territory until May 1, 2006. *See* Docket No. 01-194, PSC Order No. 5941, Hearing Examiner Report, App. A (Settlement) at ¶D.1, *aff'd sub nom. Constellation New Energy, Inc. v. Public Service Commission*, 825 A.2d 872 (Del. Super. 2003); *see also* 26 *Del. C.* §1010(a)(2). As a condition of the Commission's approval of the merger, DP&L agreed to price its SOS to the various customer classes just slightly above the retail

market prices prevailing during the earlier transition period. Subject to a few exceptions, such SOS prices would prevail until May 1, 2006. *See* Order No. 5941, Hearing Examiner's Report, App. A (Settlement) at ¶¶B, C. The SOS prices would then be reviewed in a process to select a SOS supplier for the period beginning May 1, 2006. *See* Order No. 5941, Hearing Examiner's Report, App. A (Settlement) at ¶D.1-2.

3. On October 19, 2004, noting that SOS rates in other jurisdictions had increased significantly once the supply rate freeze had been lifted, the Commission initiated Docket No. 04-391 to "explore issues related to the selection of an SOS supplier for [DP&L's] service territory and the appropriate prices to be charged for SOS after that date." (PSC Docket No. 04-391, Order No. 6490 at ¶3).

4. On March 22, 2005, in Order No. 6598 (Docket No. 04-391), the Commission reviewed a report and recommendations prepared by Staff that had been the subject of written comments and oral argument. In Order No. 6598, the Commission determined that DP&L would provide SOS in Delaware pursuant to a "wholesale" model. DP&L would secure the power to serve SOS customers from the wholesale power market but would continue to interface directly with customers.

5. In Order No. 6746, issued in Docket No. 04-391 on October 11, 2005, the Commission approved a proposed settlement providing that DP&L would provide SOS to all customer classes, with no specified termination date. The Commission approved two categories of SOS: (1) a fixed price SOS available to all customers except GS-T customers; and (2) an Hourly Priced Service ("HPS") that was mandatory for GS-T customers and optional for GS-P customers. Furthermore, the Commission directed that a competitive RFP process be used to procure the full requirements of customers eligible for fixed price SOS. Bidders would be asked

to bid seasonally, but the retail rates would be developed using the bids and converting them into the existing rate design structures. A consultant selected by the Commission would monitor and participate in the bidding process.

6. The Commission further ordered that, in order to provide rate stability for residential and small commercial customers, DP&L would initially procure 1/3 of the load with a three-year contract (which would actually be 37 months for the first three-year contract), 1/3 with a two-year contract (which would actually be 25 months for the first two-year contract), and 1/3 with a one-year contract (which would actually be 13 months for the first one-year contract).[1] Under this arrangement, by the end of the second year, there would be a portfolio of three-year contracts to serve this load, and each year thereafter, a new three-year contract for 1/3 of that load would be entered into to replace the expiring one. One-year contracts would be used for all other customer classes eligible for the fixed price SOS.

7. Pursuant to Order No. 6746, DP&L conducted a solicitation for bids to provide supply for SOS customers after May 1, 2006. The results of the solicitation process were not what the proponents of deregulation had intended: as a result of the solicitation, electric rates for residential and small commercial customers would increase anywhere from 59-112% as a result of the bids received and accepted.

8. In response to the resulting consumer outrage occasioned by the announcement of the imminent rate increases, in March 2006 the Delaware General Assembly enacted the Electric Utility Retail Customer Supply Act of 2006 (the "EURCSA"). Under the EURCSA, DPL's customers were provided the option to defer the rate increase over a three-year period (with the

[1] The purpose of the extra month in the initial contracts was to move from the May 1, 2006 start date for SOS in this proceeding to a PJM year, which commences June 1 of every year.

payment of carrying costs) or to shoulder the entire rate increase effective May 1, 2006. 26 *Del. C.* §§1006 (a)(3) and 1006(a)(3)a.

9. The EURCSA authorized DP&L, subject to Commission approval, to take any or all of the following actions in order to meet its SOS requirements: (1) enter into short- and long-term contracts for the procurement of power necessary to serve its customers; (2) own and operate electric generation facilities; (3) build generation and transmission facilities (subject to any other requirements in the Delaware Code regarding siting, etc); (4) invest in demand-side resources; and (5) any other Commission-approved action to diversify its retail load. 26 *Del. C.* §1007(b)(1)-(5). Such actions could be taken only after DP&L had filed an application to take such action or had had such action approved as part of its Integrated Resource Plan ("IRP"). *Id*. at §1007(b).

10. The EURCSA requires DP&L to file an IRP on December 1, 2006,[2] and on December 1 of every two years thereafter. *Id*. at §1007(c)(1). The General Assembly directed DP&L to "systematically evaluate all available supply options during a ten (10) – year planning period in order to acquire sufficient, efficient and reliable resources over time to meet its customers' needs at a minimal cost." *Id*. The General Assembly further instructed that the IRP set forth DP&L's supply and demand forecasts for that 10-year period and the resource mix with which DP&L proposed to satisfy its supply obligations for that period. *Id*. The General Assembly specifically forbade DP&L from relying "exclusively on any particular resource or purchase procurement process," and mandated that DP&L "explore in detail all reasonable short-

[2] In addition to the Commission, DP&L must file the IRP with the Controller General, the Director of the Office of Management and Budget, and the Energy Office of the State of Delaware (which is part of the Delaware Department of Natural Resources and Environmental Control ("DNREC"). 26 *Del. C.* §1007(c)(1).

and long-term procurement or Demand-Side Management strategies, even if a particular strategy is ultimately not recommended … ." *Id*. at §1007(c)(1)1. Finally, the EURCSA specified that at least 30% of DP&L's resource mix was to be "purchases made through the regional wholesale market via a bid procurement or auction process …" to be overseen by the Commission subject to the procurement process approved in Docket No. 04-391, as it may be modified. *Id*.

11. Under EURCSA, in developing its IRP, DP&L must "investigate all possible opportunities for a more diverse supply at the lowest reasonable cost." *Id*. at §1007(c)(1)2. The General Assembly stated that DP&L may consider the economic and environmental value of the following items: (1) resources that use new or innovative baseload technologies (such as coal gasification); (2) resources that provide short- or long-term environmental benefits to Delaware citizens (e.g., wind and solar power); (3) facilities that have existing fuel and transmission infrastructure; (4) facilities that use existing brownfield or industrial sites; (5) resources that promote fuel diversity; (6) resources or facilities that support or improve reliability; and (7) resources that encourage price stability. *Id*. at §1007(c)(1)2.(i)-(vii).

12. Finally, the EURCSA directed DP&L to file a proposal to obtain long-term contracts on or before August 1, 2006, "to immediately attempt to stabilize the long-term outlook for [SOS]" in DP&L's service territory. *Id*. at §1007(d). The General Assembly required the application to contain a proposed form of RFP for construction of new generation resources within Delaware to serve SOS customers. The General Assembly required the RFP to include a proposed form output contract which, at a minimum, would include capacity and energy, and could also include ancillary electric products and environmental attributes between DP&L and the providers of the new generation. The General Assembly specified the term of such contracts to be between 10-25 years. In addition, DP&L was directed to set forth selection criteria "based

on the cost-effectiveness of the project in producing energy price stability, reductions in environmental impact, benefits of adopting new and emerging technology, siting feasibility, and terms and conditions concerning the sale of energy output from such facilities." *Id*.

13. The EURCSA provided that the Commission and the Energy Office could approve or modify the RFP terms prior to issuance.[3] The Commission and the Energy Office were instructed to "ensure that each RFP elicits and recognizes the value of:

a. proposals that utilize new or innovative baseload technologies,

b. proposals that provide long-term environmental benefits to the state,

c. proposals that have existing fuel and transmission infrastructure,

d. proposals that promote fuel diversity,

e. proposals that support or improve reliability, and

f. proposals that utilize existing brownfield or industrial sites."

Id. at §1007(d)(1)a.-f. The General Assembly ordered DP&L to issue its RFP on November 1, 2006, and set December 22, 2006 as the deadline for receipt of bids. *Id* at §1007(d)(1).[4]

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[3] The Commission understands that it was the intent of the General Assembly that the Commission and the Energy Office have equal votes with respect to determinations regarding the RFP.

[4] The EURCSA specifically provides that:

> public service companies shall be eligible to participate in such RFP process through unregulated affiliated companies that meet the Commission's criteria to ensure that such affiliates are sufficiently financially and functionally separate from the regulated utility operations to prevent subsidization of the generation project by the regulated operations and to eliminate any other advantages from the affiliation with regulated operations.

26 *Del. C.* §1007(d)(2).

14. The General Assembly directed the Commission, in conjunction with the Energy Office, the Controller General and the Director of the Office of Management and Budget (together, the "State Agencies"), to retain an independent expert in energy procurement (at DP&L's expense) to oversee the development of the RFP and to assist the State Agencies in their review of bids received. *Id*. at §1007(d)(2). The General Assembly further ordered the State Agencies to evaluate the proposals received on or before February 27, 2006, authorizing them to "determine to approve one or more of such proposals that result in the greatest long-term system benefits … in the most cost-effective manner." *Id*. at §1007(d)(3). Once the State Agencies identify such proposal(s), DP&L is required to enter into contracts with the selected bidders. *Id*.

II. <u>THE PROCEDURAL BACKGROUND</u>

15. On August 1, 2006, DP&L filed its proposed RFP and draft Power Purchase Agreement ("PPA"). On August 8, 2006, the Commission opened this docket to perform its oversight and review of the tasks set forth in the EURCSA. (Order No. 7003). The Commission recognized the need to "move quickly on this task, to have flexibility in moving forward, and to provide for transparency throughout the complete process." *Id*. at ¶3. The Commission's goal was to allow public input into the RFP review while maintaining an efficient process for meeting the statutory deadline for issuance of the RFP. *Id*.

16. To accomplish this, the Commission first directed Staff to conduct an initial public workshop to receive input from interested parties and for Staff to ask questions and otherwise seek additional information. The Commission then sought comments form interested parties. Thereafter, Staff, together with the independent consultant, would provide a report with Staff's recommendations. Interested parties could offer responses to the report and appear before

the Commission. Based on the report and the comments received, the Commission would determine whether the proposed RFP should be modified and, if so, in what manner. *Id*, at ¶4.

17. The Commission cautioned interested parties not to view the workshop and comment process as a "device to try to steer the RFP process in a way that will have the solicitation point toward that party's own contemplated generation proposal." *Id*. at ¶5. Rather, the Commission advised interested parties that their comments and input should focus on whether DP&L's draft RFP appropriately reflected the overall IRP goals set forth in the EURCSA and whether the draft RFP would ensure that potential supply sources were not arbitrarily excluded from offering a proposal. *Id*.

18. The Commission established the following schedule:

August 18, 2006	Staff conducts public workshop
September 15, 2006	Staff submits report (in consultation with Independent Consultant) containing its recommendations regarding any RFP modifications
September 29, 2006	Written comments to report due
October 17, 2006	Commission deliberations

Id. at Ordering ¶¶ 2-4. These deadlines, with the exception of the Commission deliberations, were subsequently amended to include, among other things, a provision for the independent consultant to provide a final report on October 12, 2006. The deadlines were amended to give the public and industry representatives as much time as possible to provide comments.

19. The Commission designated James McC. Geddes, Esquire as Rate Counsel to assist the Commission and Staff. The Commission, in conjunction with the other State Agencies, retained New Energy Opportunities, Inc. and its subcontractors, Merrimack Energy Group, Inc., La Capra Associates, Inc. and Edward L. Selgrade, Esquire, as the independent consultant (together, the "IC").

20. The Commission stated that subject to its review and approval, DP&L would be permitted to recover in SOS rates the costs incurred in connection with this proceeding and the expense of the State Agencies' IC, and that it would permit deferred accounting treatment for this purpose. The Commission further directed that subject to its review and approval, DP&L's other initial costs in developing and submitting its IRP would be included and recoverable in DP&L's next distribution rate case, and that it would be permitted deferred accounting treatment (in the form of amortization) for these costs as well. The Commission put DP&L on notice, however, that all future costs would be normalized as an expense in accordance with the Commission's traditional treatment of legal expense. *Id*. at Ordering ¶¶ 6-7.

21. The Commission reserved decision on whether carrying charges (and what level) would be recoverable on the amounts granted deferred accounting treatment under Ordering ¶¶ 6 and 7. The Commission instructed DP&L to file an application for such costs when it seeks to recover those costs through revisions to SOS rates and distribution rates. *Id*. at Ordering ¶ 8.

22. Finally, the Commission directed its Secretary to send a copy of Order No. 7003 to the Energy Office, the Controller General, the Director of the Office of Management and Budget, and the DPA. *Id*. at Ordering ¶ 9.

23. On August 18, 2006, Staff held a workshop at which Staff and DP&L made presentations. Representatives of various interested parties attended the workshop, and several of those parties spoke at the workshop.

24. Between August 18-31, 2006, twelve unidentified individuals submitted written comments, and written comments were received from the following parties: Jeremy Firestone and Willett Kempton (hereafter "Firestone" and "Kempton"); NRG Energy, Inc. ("NRG"); the DPA; the Delaware Nature Society; the Delaware Energy Users' Group ("DEUG");

DNREC/Delaware Energy Office; SCS Energy, LLC ("SCS"); Bluewater Wind, LLC ("Bluewater"); and the Coalition for Climate Change Study and Action ("Coalition"). Green Delaware ("GD") filed comments on the DPA's comments on September 5, 2006; the DPA filed reply comments to GD's comments on September 7, 2006; and GD filed a response to the DPA's response on September 7, 2006. All of the comments were posted on the Commission's website.

25. On September 18, 2006, the Independent Consultant "(IC") filed its draft report on DP&L's proposed RFP.

26. Meanwhile, on September 27, 2006, Mr. Firestone filed a motion to reschedule the Commission hearing scheduled for October 17, 2006 (the "Firestone Motion"). Mr. Firestone complained that the IC's report had been filed 3 days later than Order No. 7003 required, and that although the IC's report was prepared for all of the State Agencies, it was unclear which of those State Agencies had endorsed and adopted the report as their own. Mr. Firestone further complained that on September 27, 2006, the IC filed a redlined version of D&L's RFP along with an explanatory memorandum, but no notice was provided to any of the parties regarding this filing. Mr. Firestone claimed that the IC's redlined version of the RFP differed "in significant respects" from its September 18 draft report (noting that the points assigned to the price stability criterion were different), and again claimed that although the IC's redlined version had purportedly been prepared for all the State Agencies, it was unclear which of the agencies had endorsed and adopted the redline version. Mr. Firestone stated that Staff had extended the time for other parties to respond to its report to October 3, 2006, and that Staff had represented that a final report would be submitted to the Commission on October 12, 2006, but that it was unclear whether that final report would be the IC's report or a Staff report. Mr. Firestone observed that Order No. 7003 had set the October 17 hearing 32 days after Staff was to

have filed its report, but that the hearing would now be just three business days after the revised final report would be filed. Mr. Firestone requested the Commission to order Staff to exercise its own judgment independent of other state agencies and independent of the IC and to immediately file a Staff report and redlined RFP, and to continue the October 17, 2006 hearing to October 24, 2006 "so that interested parties may have adequate opportunity to prepare" therefor.

27. At its regularly-scheduled meeting on October 3, 2006, the Commission heard argument and deliberated on the Firestone Motion. While sympathizing with Mr. Firestone regarding the difficulty caused by the tight schedule, the Commission observed that the General Assembly had established time frame and therefore the Commission could do nothing to delay the proceedings. The Commission also observed that Staff frequently retained consultants to present its position in certain circumstances; hence, that Staff had not filed its own report was immaterial. Consequently, the Commission denied the Firestone Motion.[5]

28. Also on October 3, 2006, the following parties filed comments on the IC's draft report and redlined RFP: DP&L; Firestone and Kempton; GD; NRG; SCS; Citizens for Clean Power; Bluewater; the Natural Resources Defense Counsel; the Coalition; and Kit Zak, Kim Furtado, and Marlene Rayner. All reply comments were posted on the Commission's website.

29. On October 12, 2006, the IC posted its Final Report Regarding Delmarva Power & Light Company's Proposed RFP (the "Final Report") on the Commission's website. The IC noted thereon that its report had been prepared for the State Agencies and that the Commission and the Energy Office had adopted the Final Report.

[5] Secretary Hughes, on behalf of the Energy Office, advised the Commission by letter dated October 2, 2006 that the Energy Office would defer to the Commission regarding a decision on the Firestone Motion. That letter appears on the Commission's website.

30. On October 17, 2006, the Commission and the Energy Office's designated representative, Philip Cherry, convened to hear oral argument and deliberate in open session on the Final Report and the parties' positions thereon. This is the Final Findings, Opinion and Order of the Commission and the Energy Office in this matter.

III. THE IC'S REPORT AND THE COMMISSION'S DISCUSSION AND FINDINGS

A. Legislative Perspective

31. DP&L asserted that its proposed RFP satisfied the EURCSA's requirements and provided the greatest protection to SOS customers. It argued that the Final Report failed to preserve the relationship between bid block size, corporate structure, security requirements and default risk; did not provide for diversity of bids and suppliers; encouraged mega-block bidding; and did not provide price stability or reasonable prices. Thus, DP&L contended, the Final Report failed to adhere to the EURCSA's mandate.

32. We observe that the Final Report took into consideration the parties' comments at the August 18, 2006 workshop, the written comments filed in August 2006 and the reply comments filed in October 2006. The Commission and the Energy Office are persuaded that, at this very young stage of the proceedings, we should approve RFP provisions that result in a greater number of bidders being permitted to bid, rather than approving provisions that limit the number of bidders. Staff described such an approach during oral argument as a "big funnel," and we find that description particularly apt: a "big funnel" approach, which will allow a broader pool of potential bidders to submit bids, is preferable to an approach that precludes potential bidders from even bidding. We believe that the problems (or lack thereof) with particular bids or bidders can be (and are better) assessed at the evaluation stage, when DP&L and the Commission and the Energy Office are reviewing and evaluating the bids received. Bids that are deemed to be

too risky or too polluting or too large (or that suffer from some other perceived flaw) during the evaluation process will be weeded out at that point and will not make it through the narrow neck of the funnel. Having carefully read and considered all of the parties' submissions, and having heard their arguments, we believe that the IC's Final Report creates that "big funnel:" its proposed RFP provisions are more inclusive and as such will permit more bidders to submit bids than DP&L's proposed RFP, which we believe is too restrictive. Thus, inclusiveness is the factor that drives us as we review the proposed RFP provisions and the Final Report and assess those provisions against the statutory requirements. For these reasons, we believe that the Final Report best captures the legislative intent behind the EURCSA. (Unanimous).

B. Relationship Between RFP and IRP and Between Delmarva and State Agencies

33. DP&L described the bid evaluation and selection process as follows in the RFP:

> [DP&L] shall determine whether [the proposals submitted] meet all threshold requirements, and among those proposals, shall select the highest rated one(s) for evaluation under [DP&L's] Integrated Resource Plan.
>
> The proposal evaluation process will culminate in the selection of an approved bidder(s), subject to the results of the Company's IRP to be filed with the Commission on or before December 1, 2006. The IRP process will evaluate available supply and demand-side options during a ten (10)-year planning period in order to provide efficient and reliable resources required over time to meet its' customers' needs at a reasonable cost. The IRP will be amended after its filing date with the results from the RFP. If the winning proposal(s) results in a more cost-effective IRP, [DP&L] will then negotiate with bidder(s) to execute a PPA.

34. DP&L goes on to state that if it selects a winning bidder(s) in the RFP process, it will inform the State Agencies of its selection(s), and if the State agencies approve their selection(s), DP&L will negotiate with the bidder(s) to execute a PPA "subject to the results of the IRP process and a final [DP&L] decision."

35. The IC questioned DP&L's description of its role in the bid evaluation process vis-à-vis the State Agencies and their Independent Consultant. Under the EURCSA, the State Agencies, with assistance from their Independent Consultant, are responsible for evaluating the proposals and deciding whether contracts should be approved. DP&L's RFP, however, discussed its own role in the evaluation and selection process and mentioned the State Agencies only as a reviewer of proposals *after* DP&L had already evaluated them. This was incorrect under the EURCSA. The IC stated that the RFP process would best be performed if both the State Agencies (and their Independent Consultant) and DP&L (and its consultant) coordinate their roles in the evaluation process. Upon receipt of proposals, DP&L should promptly forward them to the State Agencies' Independent Consultant for it to perform its review. Should DP&L make any threshold determination to reject a particular bid(s), that determination should be subject to the review and approval of the State Agencies and their Independent Consultant. Both the State Agencies (through their Independent Consultant) and DP&L should perform detailed bid evaluations in parallel with each other, with the Independent Consultant conducting its own evaluation where it has the analytical tools to do so and reviewing DP&L's analysis where it does not.

36. DP&L also proposed to provide a confidential report to the Commission regarding the bid evaluation results. The IC agreed that such a report should be provided, but believed that a public version of such report should also be available. The IC stated that the RFP process' integrity was best served by the Independent Consultant working together with DP&L to reach a consensus on bid evaluations and to try to resolve any differences that may arise.

37. The IC rejected as "unacceptable" DP&L's proposal to provide the State Agencies and their Independent Consultant with the key assumptions for its economic analysis

after it had conducted its analysis. The IC noted that the State Agencies were responsible for the RFP and for the determinations regarding the outcome thereof. Thus, price- and non-price-factor evaluation methodologies and input assumptions must be provided to the State Agencies and their Independent Consultant so that they can be thoroughly vetted *before* bids are evaluated; otherwise, the State Agencies could not have adequate assurance that bid evaluations will be properly conducted in accordance with the EURCSA timeframe and directives.

38. Finally, the IC supported DP&L's proposal to update the IRP with the highest ranking bids from the RFP and to revise the RFP to indicate that the updated IRP would be filed by a certain date. However, the IC cautioned that that date should be substantially before DP&L and the Independent Consultant file their reports concerning the outcome of the RFP process with the State Agencies. The IC contended that this would be consistent with the EURCSA's intent, which was to provide sufficient information to the State Agencies to enable them to make their determinations as to the proposal(s) to be accepted by the end of February 2007.

39. Several participants expressed concern that tying the RFP process to the IRP could result in lengthy delays and considerable uncertainty. The IC observed that such a result would be inconsistent with the EURCSA, and could be avoided by using consistent evaluation methodologies for both the RFP and the IRP. If this were done, a proposal evaluated as being cost-effective under the RFP process should also rank high in the IRP process (at least with regard to the economic analysis).

40. We agree with the IC's recommendations on this issue. We note in this regard that DP&L has stated that it intends to update its IRP with the RFP results, and therefore relate the RFP to the IRP. While we recognize that the IRP provisions speak specifically to minimal cost, lowest reasonable price and the like, we do not believe that this means that price is not a

consideration in the RFP process. Indeed, the State Agencies are directed to select *cost-effective* projects that meet the criteria set forth in the EURCSA. Since the General Assembly specifically included that language, we must conclude that the State Agencies are to consider price as a factor in reaching a decision on the bids submitted in response to the RFP. (Unanimous).

C. <u>Objectives and Criteria for Use in Determining RFP Design Issues</u>

41. It is important to have objectives and criteria for addressing RFP design issues. Many such objectives and criteria are set forth in the EURCSA itself, such as ensuring that the RFP elicits and recognizes the value of proposals that use new or innovative baseload technologies; that provide long-term environmental benefits to the state; that have existing fuel and transmission infrastructure; that promote fuel diversity; that support or improve reliability, and that use existing brownfields or industrial sites. The EURCSA also directs the State Agencies to approve one or more proposals that result in the greatest long-term system benefits (including those benefits just identified) in the most cost-effective manner. Likewise, in developing its IRP, the EURCSA directs DP&L to evaluate all supply options during the 10-year planning period to acquire the resources to meet customer demand at a minimal cost.

42. According to the IC, a successful RFP process should be designed to facilitate the greatest amount of bidder participation. Risks should be fairly apportioned between buyer and seller: if the risks to the seller are too great, the seller will not bid, or, if it does bid, its price will be higher to hedge against the risks. On the other hand, there are very real risks to buyers under long-term contracts, and the RFP process must be concerned with those risks as well. The RFP process should be designed to "weed out" those projects that do not have a reasonably high likelihood of being built for whatever reason (siting issues, financing), and there should be adequate security to mitigate higher replacement power costs in the event of project failure or

default, but the required security should not be so onerous as to deter participation. In designing its RFP process, the IC took the approach of encouraging bidders and protecting DP&L and customer interests using terms already prevalent in the industry, in conjunction with the EURCSA's limitations and objectives.

43. Many participants argued that price should not be a factor in the RFP process, contending that while the IRP sections of the EURCSA contain several references to price, the RFP sections of the EURCSA do not. At the October 17, 2006 meeting, Mr. Firestone specifically asked us to rule on this matter. We find price should be encompassed in the RFP process. The IC observed, and we agree, that the General Assembly was interested in fostering price stability at a reasonable price. Price stability is important, but only if the level of the stable price is reasonable (that is, it is "cost-effective"). The proposals that are likely to be successful are those that achieve the greatest long-term system benefits as enumerated in the EURCSA in the most cost-effective manner. (Unanimous).

D. Contract Size/Plant Location/Bid Deposit/Products to be Purchased/ Regulatory-Related Issues

44. ***Contract Size.*** DP&L proposed a maximum project size of 200 MW, with a minimum size of 25 MW for renewable resource projects and 50 MW for non-renewable resource projects. Its rationale for limiting the project size to 200 MW was that it did not want to depend too heavily on one source for SOS. In 2005, DP&L's SOS customers consumed fewer than 200 MW during 2% of the annual hours and the average hourly load of its Delaware residential and small commercial customers was 400 MW. From October 2004 through September 2005, DP&L's maximum peak load for Delaware residential and small commercial SOS customers was 1,028 MW. DP&L provided a weather-normalized preliminary forecast of Delaware residential and small commercial customers for 2006-16, which showed a decrease in

loads (before any migration) from 2004-05 that did not reach 2004-05 levels until 2011, and projected a 2% growth rate thereafter. DP&L stated that its proposed size limitation was in compliance with the EURCSA requirement that 30% of SOS supply be obtained from the wholesale market through a bid/auction process.

45. NRG and SCS argued that the 200 MW limitation was too low and would not support financing of the size of plant that would be economical to build.[6] NRG contended that the 200 MW limit did not take into account the size necessary to support a new, economical coal gasification plant; that the 30% wholesale competitive procurement requirement was a minimum and did not suggest a maximum capacity purchase size; and did not take load growth over the years into consideration. SCS recommended increasing the maximum project size to 1000 MW. NRG also recommended a larger maximum project size, but did not identify a specific maximum size. Bluewater proposed that the limit be stated as an energy limit rather than an capacity limit, so that lower capacity factor projects (like wind) could propose a higher level of capacity,[7] and suggested a 600 MW maximum nameplate capacity contract size for wind only. Messrs. Firestone and Kempton recommended that the maximum contract size be based on the energy output of a 400 MW plant at a 100% capacity factor, so that a 900 MW wind plant operating at a 40% capacity factor would come within the size limit.

47. The IC proposed a 400 MW contract size limit. Initially, it observed that, because at least 30% of DP&L's SOS supply must be procured under competitively-bid wholesale

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[6] NRG plans to build an integrated coal gasification combined cycle plant, which it claims must be sized upwards of 500 MW to be economically feasible. NRG also announced plans to repower its Indian River plant.

[7] An offshore wind project might have a capacity factor in the 35-45% range, while a coal gasification plant might have an availability factor of 80-85% once they are mature and a

contracts, no more than 70% of the SOS supply requirement could be procured under long-term contracts. The IC noted that DP&L's preliminary growth projections for the 2006-16 period seemed conservative in light of PJM's projections of 2.7% growth over the next 5 years and significant continuing load growth over the longer term. In light of these facts, the IC found a 400 MW contract size supportable.

48. The IC rejected DP&L's contention that its load data supported its proposed maximum contract size. The IC was not "overly concerned" that there would be many hours in the year that a plant's output under a 400 MW contract would be greater than the residential and small commercial SOS load. The IC agreed with DP&L that these were lower value hours, but the relative cost and benefit of a baseload unit would be considered in the economic analysis of the project. Furthermore, the plant may have substantial ability to reduce its output during off-peak hours when costs are low, or to sell excess power back to the market on a spot basis or under term contracts. In addition, with increasing load growth, off-peak loads would increase. Finally, the IC recommended an adjustment to the maximum contract size for baseload projects that offered little or no operational flexibility (the ability to ramp down output from full load); in that event, the maximum contract size would be reduced to the product of 400 MW and 70% (capacity factor) divided by the project's target Equivalent Availability Factor ("EAF") (a percentage). The IC concluded that 400 MW contracts (with the proposed size adjustment) would provide price stability benefits. The IC's "fundamental concern" with DP&L's 200 MW limitation was that it did not consider the size of plants that could economically be built and the size of contracts that might finance them.

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capacity factor of 70%. They are also likely to have a degree of ramp-down capability in off-peak hours (ramping down to 50-70% of their full load capability).

49. The IC's "fundamental concern" with those suggesting a 600 MW limitation was that they failed to consider that the purpose of an RFP process is to solicit a long-term physical hedge for DP&L SOS customers for price stability purposes and that a contract that is too large creates problems for customers. The IC observed that the energy from a 600 MW wind project might be less than that from a 400 MW baseload project on an annual basis, the intermittent nature of wind energy could result in energy produced that could substantially exceed 400 MW when loads are low and, conversely, little or no production when loads are high, which would lead to more of a mismatch in terms of a hedge and would produce less value for DP&L customers.[8]

50. The IC recognized that financeability of projects was an important consideration, but the question of sizing a power sale contract must be evaluated in a commercial context under the EURCSA's limitations. The IC contended that it was not reasonable for a distribution utility to substantially "over-hedge" itself, even if this resulted in somewhat higher unit purchase costs or difficulties for a developer in financing a project. The IC observed that projects with subscription percentages in the 56-80% range had been financed and built. It recognized that coal gasification and wind might have a higher bar than more conventional technologies, but there were other opportunities for the developers of such projects to hedge their energy market price risks through bilateral contracts with other buyers, swaps, or other financial transactions. In short, the IC concluded, a line had to be drawn, and the IC drew that line at 400 MW.

51. The IC countered SCS's argument regarding larger maximum contract sizes by noting that it was unlikely that the customer classes supporting those larger maximum limits

[8] The IC observed that a 600 MW wind project would be twice the size of the largest wind project in the United States and would be approximately 30% larger than the offshore wind

were as small as DP&L's SOS class. The IC also rejected SCS's suggestion that size simply be an evaluation factor, noting that most RFPs contained limits on the maximum size of a project.

52. Finally, the IC recommended no minimum size requirement. It noted that smaller projects such as landfill gas projects could be economical and could provide substantial long-term environmental benefits. The IC believed that the proposed restrictions were unnecessary and would unduly limit the pool of potential bidders.

53. We agree with the IC. In keeping with our "big funnel" approach, we do not believe it is appropriate to limit the size of a contract to 200 MW. The IC has given cogent reasons why the limit should be increased to 400 MW with the proposed size adjustment for projects that lack the flexibility to ramp down. We believe that that size limitation strikes the appropriate balance between the risks to be borne by the SOS customers and the risks to be borne by the developers. At the same time, we also realize that Section 1007(b)(1) of the EURCSA states that any long-term contract is for the procurement of power to serve DP&L's SOS customers. Nevertheless, to say that we believe that developers should be able to bid larger projects is not to say that we will find such a project to be worthy of selection at the end of the day. We understand that there are risks and dangers associated with larger contracts, and we will evaluate them closely if and when the time comes. (Unanimous).

54. ***Plant Location.*** Consistent with the EURCSA , the proposed RFP is open to any new generation projects located in Delaware, whether or not in DP&L's service territory. Bluewater, which claims that it will submit a bid for development of an offshore wind energy facility, proposed to include language that would include its project as being a new generation resource within Delaware. The IC concluded that Bluewater's proposal, pursuant to which its

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project being developed for Cape Cod. A 600 MW wind project would represent the largest transmission lines would make landfall in Delaware, to be consistent with the EURCSA. No other party objected to Bluewater's proposal, and we too find it to be consistent with the intent of the Legislature to encourage as many projects as possible to bid. (Unanimous).

55. ***Bid Fee.*** The proposed RFP requires bidders to pay a non-refundable $10,000 fee when they submit their bids. The DPA contended that the fee should be $3,000. The IC noted that bid fee provisions are common for competitive power procurements, as they tend to discourage less-serious bidders. For projects smaller than 50 MW, however, the IC proposed a bid fee of $200 per MW, with a minimum bid fee of $500. DP&L objected to the sliding scale bid fee on the ground that the Renewable Portfolio Standard ("RPS") provided opportunities for smaller renewable projects and that no accommodation in bid fee was necessary. The IC pointed out that the RPS is a requirement regarding load serving entities' purchase of renewable energy credits and does not involve the purchase of energy and capacity, which is the RFP's primary subject. The IC concluded that its proposal would facilitate robust bidding. The IC also recommended allowing a bidder to propose up to three variants for each bid deposit per proposed generating resource (the differences may include price, contract term, guaranteed completion dates or other variables); however, if a bidder proposed a project on a different site or using a different technology, that would be considered a separate bid and would require payment of a separate bid fee.

56. We agree with and approve the IC's recommendations. We believe that the proposed sliding scale bid fees for smaller projects may foster additional bidding. A $10,000 fee for a project that is fewer than 50 MW seems onerous when one considers that a bidder proposing a 400 MW project would pay the same $10,000. (Unanimous).

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proportion of installed wind capacity in the United States, and, perhaps, internationally.

57. ***Products To Be Purchased. (i) Energy – Unit Contingent Versus "Firm."*** DP&L proposed making the bidder responsible for delivering energy from the plant and for the cost of replacement power whenever the plant is unavailable to produce energy. It stated that the size and form of the energy contract must be comparable to the energy output expectations of the new generation. DP&L would structure the energy contract based on a contractual capacity factor intended to reflect the operating characteristics of the new generation whereby the bidder would be at risk for underperformance. DP&L further proposed that unavailability of the generating unit would not relieve the bidder of its obligation to deliver energy even in the case of a force majeure event. Finally, a bidder's failure to deliver any product more than five times in a calendar year would entitle DP&L to terminate the PPA and seek damages for replacement power costs. (The Delivery Point is required to be in the "Delmarva Zone," defined as the aggregate of busses as listed on the PJM website and aggregated by DP&L; this will be discussed in greater detail later in this Order).

58. NRG contended that sellers should not be required to provide system firm power when a plant suffers a forced outage. Because the PPA's capacity payments are based on Unforced Capacity ("UCAP"),[9] the seller should not be obligated to obtain or pay for replacement power in the case of a forced outage because it will already receive reduced capacity payments. NRG argued that it should have the right (but not the obligation) to delivery energy when a plant is down at the lower of the contract price or the market price and have the plant be considered available for capacity payment adjustment purposes. Bluewater questioned how DP&L would structure a PPA for wind power based on its "anticipated capacity factor."

[9] "UCAP" is the installed net summer capacity rating of a generating unit, adjusted by its equivalent forced outage rate ("EFOR").

60. The IC called DP&L's proposal "highly unconventional." Requiring a seller to provide replacement power when a unit experiences a forced outage would make financing problematic for a developer. Typically, the industry practice for a dispatchable power project is to adjust a seller's capacity payment based on the project's EAF, in which a seller is effectively penalized by reduced capacity payments and the buyer is effectively compensated by making reduced payments to the seller. The value of performance during key peak periods can be recognized in structuring the capacity payment adjustment provisions. The IC proposed specific capacity payment adjustment terms that emphasized the importance of superior performance during peak daily and seasonal periods.[10]

61. The IC opposed NRG's proposed option to provide replacement power when its plant is unavailable or not called upon to produce energy. The IC pointed out that the capacity payment adjustment provisions were a form of liquidated damages for substandard performance. While liquidated damages may be higher or lower than actual damages, they provide a mutually agreeable way of relating payment to performance and the value of performance. If one party could provide power from another source only when it would be less costly than incurring the impact of liquidated damages, it would skew the impact of the liquidated damages to that party's benefit. In the IC's view, this was unfair to both DP&L and its customers.

62. The IC further recommended that sellers have the ability to bid unit-contingent energy. As no potential bidder had expressed interest in bidding firm energy, the IC suggested that the standard contract be based solely on a unit-contingent energy product. DP&L contended

[10] The IC stated that typically, a coal project had high capacity payments and low energy payments, so there would be a strong incentive to maintain high availability. Wind energy projects, on the other hand, typically produced intermittent energy and relatively little in the way of recognized capacity, and so they typically had high energy payments and low capacity payments.

unit-contingent contracts would create various problems for it and its customers regarding the supply and receipt of full requirements service and management of the associated risks. The IC concluded that the risks should be manageable by DP&L through contracting with one or more energy marketers or through market sales. Moreover, the PPA would have strong risk mitigants in the availability adjustment provisions, security and other contract provisions.

63. **(ii) *Capacity – UCAP.*** DP&L proposed to pay a seller for the amount of UCAP that PJM recognizes. The amount per kW per month will be set forth in the PPA. PJM has rules for assigning EFOR for different types of generating units in their initial years of operation (since there is no substantial performance history for a new unit, the historical track record of similar units is applied). If PJM has not assigned a UCAP amount to a project, DP&L would allow for an automatic adjustment once PJM did so.

64. The IC recommended that all sellers should be required to provide UCAP to DP&L under the PPA. The IC further recommended using a capacity payment adjustment provision that reflected UCAP but that also took into consideration planned outage time and the greater importance of reliable performance in peak periods. DP&L argued there was an inconsistency between using this methodology for payment purposes and PJM operation, but the IC dismissed that argument, stating that an equivalent availability adjustment provision is common in the industry for unit contracts.

65. NRG proposed a floor for UCAP during the first three years of operation so that it would obtain the higher of UCAP credited by PJM and a specified floor value. The IC proposed that a seller could propose guaranteed availability targets for different contract years.

66. ***(iii) Ancillaries and Environmental Attributes.*** The EURCSA permits DP&L to purchase ancillaries (such as spinning reserves, regulation and operating reserves) and

environmental attributes ("EAs") but does not require it to do so. DP&L's proposed RFP required bidders to supply any and all ancillary services and EAs that will be used to serve SOS load along with the capacity and energy from that unit. The IC observed that PPAs commonly incorporate ancillary services and EAs, and supported including them in the RFP based on the following conditions:

- DP&L should specify that it desires to purchase the ancillary services recognized by PJM, and each bidder should identify the products it proposes to provide and the limitations under which it can provide them. Additionally, DP&L should specify that the benefits of providing ancillary services will be considered in its evaluation.

- Projects that will not provide ancillary services or that will provide only limited ancillary services (e.g., wind projects) will not be penalized in the evaluation, and their capacity, energy and renewable energy credits will be fully valued. There is no requirement that a bidder bid an ancillary service that its proposed project cannot provide.

- DP&L should exclude EAs and replacement reserves from the definition of ancillary services. These are not ancillary services as defined by PJM. NRG argues that a seller should not be required to provide any ancillary service that is created after a PPA is executed; however, the IC recommended that sellers should be required to provide a newly-defined ancillary service (a) to the extent the generating unit can provide it without any material increase in operating or capital costs or material decrease in revenues or (b) if there are material costs and/or changes required and the buyer agrees to hold the seller harmless in order to secure delivery of the future product.

- The IC called DP&L's definition of EAs "overly broad." The proposed PPA suggested that all of a seller's allowances for SO_2, NO_x and CO_2 must be conveyed to the buyer; but the RFP stated that the seller was entirely responsible for compliance with all environmental laws and for having the required offsets, allowances and credits it needed relative to plant output. The IC suggested defining EAs to incorporate (a) renewable energy credits from eligible renewable energy resources pursuant to the RPS or any other renewable portfolio standard (or any other claim based on the renewable nature of the energy produced by the plant); and (b) any claims that the production of energy that DP&L purchases had the impact of reducing emissions elsewhere. The IC observed that Bluewater had expressed concern that EAs other than renewable energy credits would be required to be conveyed to DP&L without being properly valued; thus, the IC recommended that the definition of EAs include only renewable energy credits so that sellers such as Bluewater would retain any potential EA value not encompassed within the transfer of renewable energy credits.

- The IC recommended limiting the number of renewable energy credits that DP&L could purchase under the PPA based on the expected output of the project and DP&L's projected obligation under the RPS relative to SOS load. The IC noted that the RPS percentage increases from 1% in the compliance year beginning June 1, 2007 to 10% in the compliance year beginning June 1, 2019, and that it is 5% for the compliance year beginning June 1, 2013. One renewable energy credit is created for each 5 MWh of energy produced by an eligible renewable energy facility. Thus, the IC recommended a cap on the amount of renewable energy credits that DP&L may purchase based on a projection of its SOS load in future years multiplied by its projected RPS obligations. Based on DP&L's load projections assuming a small amount of migration, the RPS minimum percentages per compliance year, the 70% limit on RFP procurement, and recognizing that renewable energy credits can be banked for three years, the IC recommended purchase limits of 65,000 in 2010, 85,000 in 2011, 105,000 in 2012, 135,000 in 2013, 150,000 in 2014, and 175,000 after 2014. The IC noted that this equates to production from a 19 MW facility at a 40% capacity factor in 2010 to 50 MW in 2015. The IC further observed that in order to properly evaluate the benefits of renewable energy credits included in any bid, DP&L would have to generate renewable energy credit price projections.

67. ***(iv) Delivery Point.*** DP&L proposed that the "Delmarva Zone" (as previously defined) be the Delivery Point for energy and capacity. DP&L would not be responsible for designating proposed projects as a network resource. The IC agreed with DP&L on the proposed delivery point. It observed that from a pricing perspective, the seller was responsible for marginal congestion and losses (positive or negative) from their point of connection compared to the Delmarva Zone. However, generators would have the option to deliver to an interconnection point in the Delmarva Zone and for DP&L to consider the risk of marginal losses and congestion in the bid evaluation, with the understanding that this portion of the bid would be evaluated from both price and price stability perspectives. If a bidder chose the second option, and losses and congestion were critical to the RFP result, DP&L should provide the bidder the opportunity to reduce congestion and losses at its expense, but only if there is adequate time to accommodate

the bidder. The IC further recommended that if DP&L proposed a self-build project in the IRP process, the matter should be reviewed to ensure there is no undue preference.

68. We agree with the IC on all of these issues for the reasons given by the IC. Again, we note that our goal in this proceeding is to ensure that the maximum number of potential bidders has the opportunity to bid, consistent with the strictures of the EURCSA. We believe that the IC's recommendations best achieve that goal. We further observe and assure the parties that we will carefully review the proposals received to determine if and how they affect DP&L's SOS customers. (Unanimous).

E. Output Contract

69. The EURCSA requires DP&L's RFP to contain a proposed PPA, which must include capacity and energy and may include ancillary services and EAs, and which has a term of between 10-25 years. DP&L's RFP did not contain such a contract, however; instead, DP&L provided a Term Sheet titled "Key Commercial Terms of Power Purchase Agreement." DP&L proposed that the Term Sheet contain the "non-negotiable legal terms governing the purchase of energy and capacity," and that interested parties register to receive a copy of the PPA one month before bids are due. NRG proposed that DP&L provide the proposed PPA to bidders as soon as possible.

70. The IC cautioned that if DP&L's approach was adopted, it would be difficult for the Commission and its Staff to review the PPA, as required by 26 *Del. C.* §1007(d)(1), prior to the submission of the standard PPA contract. Consequently, the IC recommended that DP&L be required to provide the proposed draft standard PPA for Commission review no later than November 1, 2006. The IC expected that the Commission would direct DP&L to issue the draft standard PPA, as modified. by November 14, 2006; however, if the Commission was not going

to rule on the issues addressed in the proposed Term Sheet on October 17, the IC recommended giving DP&L up to 10 business days from the date the substance of the Commission's ruling was conveyed to DP&L to provide the draft standard PPA for Commission review.

71. We agree with and approve the IC's recommendation. Since we did not rule on all of the issues to be included in the term sheet during our deliberations on October 17, 2006, we will allow DP&L through the close of business on November 6, 2006 to submit the PPA. (Unanimous).

F. <u>Regulatory Out Clause; Related Regulatory Issues.</u>

72. The IC observed that initial conditions precedent for regulatory approval are commonplace in standard long-term PPAs, and that parties understand that until the buyer receives the necessary regulatory approvals, a significant commitment of capital to the seller's project cannot be made. In this light, the IC considered DP&L's condition precedent of regulatory approval conceptually acceptable. The IC further concluded that it was "fair and reasonable" to provide DP&L with pre-approval of its entry into a PPA and appropriate assurances of cost recovery through a regulatory mechanism, noting that the EURCSA specifically provided that all reasonable costs of the PPAs shall be included in SOS rates.

73. DP&L also sought to include a provision in the PPA that would permit it to terminate the PPA without liability if, at any time after the defined "Initial Delivery Date," DP&L were not permitted to recover all amounts payable under the PPA. NRG and Bluewater objected on the ground that such an escape clause would preclude financing.

74. The IC observed that after regulatory approval, any subsequent "regulatory out" would present "insurmountable barriers to the financing of a project." The IC noted that capital

would not be available for a project that might at any time during or after construction lose the power revenues supporting the investment. Thus, the IC recommended deleting this provision.

75. DEUG took the position that no costs of the IRP process, the RFP process or any PPA should be assigned to distribution service rates or hourly priced SOS. DEUG argued that the PPA could lead to higher SOS rates, and that a non-bypassable charge should not be added to distribution rates to protect SOS customers even though the EURCSA would allow this. The IC stated that there was always the potential for a PPA to cause SOS prices to be above market at some time during its term. The IC opined that little if any value would be gained if the Commission limited itself (now or in the future) from ever assessing non-bypassable charges to distribution customers due to PPA costs; indeed, the IC thought that doing otherwise would subvert the EURCSA's fallback mechanism in 26 *Del. C.* §1010(c). The IC deferred to the Commission's rate counsel on the question whether related costs could ever be assigned to hourly-priced SOS customers.

76. We agree with and approve the IC's recommendations. We believe that permitting a buyer to exercise a regulatory out at any time after a PPA is signed would in fact create tremendous problems with respect to project financing, and that this would defeat our goal of encouraging more bidders to participate in the RFP process. Again, we emphasize that we will evaluate the bids submitted quite closely to gauge their effect on DP&L's SOS customers. We understand the risk, pointed out by DEUG, that at some point a long-term PPA would be above market, but we believe that the General Assembly also understood that risk and determined that it was a risk that may be worth taking. (Unanimous).

G. <u>Threshold Requirements</u>

77. ***Notice of Intent to Bid.*** The RFP requires all bidders to submit the required Notice of Intent to Bid ("NOIB") by the end of the day on November 22, 2006. Bidders are also required to provide DP&L with the necessary information to permit DP&L to undertake a "transmission impact study" on the NOIB form. DP&L's reason for establishing a NOIB as a threshold requirement is based on the time frame for completing the evaluation process and its need to undertake the transmission impact study prior to receipt of bids. The IC observed that this threshold criterion was not common in other RFPs, but that DP&L's rationale was reasonable, and therefore did not object to it.

78. We agree with the IC and do not object to the inclusion of NOIB in the RFP. (Unanimous).

79. ***Credit Requirements.*** DP&L listed three credit requirements for bidders to satisfy the credit threshold:

- Each bidder must demonstrate sufficient financial wherewithal to finance the proposed project, including evidence of its credit rating, short-term debt rating, total net worth, financial statements, liquidity and financial stability.
- The bidder's net worth must be as least as large as the total capital required for the project.
- Bidders and/or guarantors must have an investment grade rating for senior unsecured debt or have equivalent financial standing.

DP&L argued that it was crucial for a bidder or guarantor to have an investment grade rating, claiming that the default rate for non-investment grade companies is more than ten times higher than investment grade companies; that its current credit rating and size reduce its flexibility to take on significant additional risk, and that a non-investment grade supplier (especially one supplying a major portion of the load over the long term) would markedly increase its counterparty risk and exert downward pressure on its bond rating. DP&L claimed that limiting participation to investment grade bidders was a necessary and cost-effective way of controlling the adverse financial impact of a supplier's default. DP&L also attempted to clarify the net worth requirement, which it contended would reduce the probability of default and thus reduce the risk to its customers.

80. Several bidders objected to these credit requirements. SCS asserted that the net worth and investment grade requirements would effectively exclude bids by special purpose entities, and would also make it highly unlikely that the RFP would generate any bids for new or innovative baseload technologies such as coal gasification. Bluewater contended that requiring an investment grade rating discriminated against smaller private companies and that it was too stringent and expensive for a project-based bid. It suggested that it might be more advantageous for DP&L to consider non-investment grade bidders with a project finance structure where a second lien is provided as collateral, the seller has no other obligations, or the project maintains a higher equity ratio. NRG recommended including objective criteria in the RFP demonstrating the bidder's ability to obtain financing so as to discourage incredible bids, while limiting the review of credit criteria only in connection with an evaluation of the proposed project level entity for all bids. NRG contended that there was no evidence that contracting with a project level entity would expose customers to additional default risk of the entity's bankruptcy.

81. The IC observed that credit requirements were one of the most contentious issues in competitive bidding processes, and that resolving the issue required a careful balancing of interests. The IC believed that the better approach was to rely on the level of security, but as a threshold matter require the bidder to demonstrate an ability to provide the security. The IC supported security requirements in the higher range of what was commercially reasonable in light of DP&L's size and credit rating. Moreover, the IC recommended incorporation of an

"Exposure" category as an evaluation factor to explicitly take a party's credit rating into consideration in the evaluation process along with contract size, contract length and operational flexibility.

82. All other things being equal, the IC agreed with DP&L that an investment grade counterparty is substantially more desirable than one who is not investment grade. However, the IC believed that the issues must be understood in a broader context: that counterparties were likely to be project companies, not energy marketing companies; the contracts would be unit contingent contracts for new generation, not firm system sales; and any contracts entered into would be at the direction of the State Agencies pursuant to legislation that provides a regulatory mechanism for DP&L to recover costs approved by the State Agencies. The IC noted that default rates of project companies with unit contracts under long-term PPAs were relatively small once the projects were in construction or operation, and that project development failure was much higher due to permitting and other risks. It noted that the default rates of company bonds that were below investment grade were not representative of default rates of project financings. Under the statutory scheme and the use of PPA as a price stabilizing mechanism, the IC found that it was highly unlikely that DP&L's shareholders or bondholders would be at risk for a project's failure at the development stage. The IC noted that although the long-term price stability benefits that would not be effective for many years into the future would be lost, no near-term cost would be incurred. The IC also noted that DP&L would draw down the letter of credit and those funds presumably would accrue to the benefit of its SOS customers (which would offset the loss of the long-term price stabilization contract). Furthermore, if there were a default while the project was operating, DP&L would be protected by both an operational period letter of credit and a second secured lien on the project. Moreover, unlike a competitive energy

supplier, DP&L would be able to seek regulatory relief if its dual position as a secured party proved inadequate in terms of cost recovery. Finally, the IC observed that the companies that DP&L identified as having defaulted on contracts had been investment grade.

83. We agree with the IC that the threshold credit requirements should not be so stringent as to eliminate bidders that are not investment grade at the outset or that do not have the net worth DP&L proposes to require. The creditworthiness of bidders will be closely examined in the evaluation process. Again, at the beginning of this process, we are loath to impose artificial barriers to foreclose potential bidders from participating. Thus, we agree with the IC that participation in the RFP process should not be limited to investment grade bidders only or firms that do not have a specified net worth, and that other bidders may also submit bids and will not be disqualified solely because they are not investment grade or do not have a specified net worth. (Unanimous).

84. ***Variable Interest Entity Treatment.*** As a threshold requirement, DP&L stated that it was unwilling to be subject to accounting and tax treatment that results from Variable Interest Entity ("VIE") status as set forth in Financial Accounting Standards Board Interpretation No. 46 ("FIN 46"). FIN 46's primary objective is to provide guidance on the identification of, and financial reporting for, entities over which control is achieved through means other than voting rights. If a proposal is deemed to be a VIE under FIN 46, it will be consolidated on DP&L's balance sheet, and DP&L will be required to carry the project on its books without having any control over the entity's operation (except through contract). Thus, DP&L asked bidders to supply all information necessary for DP&L to make the VIE assessment, including data supporting the unit's economic life, the fair market value, executory costs, non-executory costs, investment tax credits and other costs (including debt specific to the proposed project).

85. Bluewater agreed with DP&L's position regarding VIE treatment. NRG asked for clarification of the information bidders would be required to submit, claiming that DP&L's description was too vague; it also challenged DP&L's need for the bidder's tax treatment regarding its investment. SCS acknowledged that the implications of FIN 46 and the PPA's balance sheet impact were legitimate concerns, but contended that the issue should not be considered in bid scoring or evaluation; rather, the RFP should advise bidders that upon selection of a bid, these issues may need to be resolved among the Commission, the bidder and DP&L.

86. The IC noted that it was common for utilities to take this position on FIN 46 and VIE treatment. However, a key issue was the information that would provide the basis for the utility to determine that a particular project would trigger VIE treatment. The IC conceded that the basis for making this determination was "murky at best," and although several major accounting firms had issued opinions on FIN 46, it appeared that the determination of whether a proposal triggers FIN 46 depends on the specific structure of each entity and the nature of the PPA. The IC contended that if DP&L was to be the sole decider of whether a particular proposal triggered VIE treatment, then it should clearly set forth in the RFP the information it requires and the methodology it will use to make that determination.

87. The IC stated that in its experience, it was better to resolve the issue at the onset of the process. The IC concluded that DP&L could include VIE treatment as a threshold issue, but it needed to provide more clarification of the required information and the standards it would use to assess each proposal. The IC observed that in their 2005 RFPs, both Puget Sound Energy and Hawaii Electric Company outlined specific information required from bidders for them to determine whether VIE treatment was triggered. In the event of an adverse decision by DP&L,

the IC recommended that DP&L be required to provide a timely written justification to the State Agencies and their Independent Consultant so they could adequately review the decision.

88. We believe it is appropriate for bidders to supply all information necessary for DP&L to determine whether it will become subject to VIE treatment as a result of entering into a particular project, including but not limited to data supporting the unit's economic life, the fair market value, executory costs, non-executory costs and investment tax credits or other costs (including debt specific to the unit being proposed) associated with the bidder's proposal;. We believe that bidders should be required to demonstrate that consolidation under FIN 46 will not occur under their proposals, and to provide supporting information sufficient to enable DP&L to make this determination. If DP&L (or its auditors) determines that a proposal will trigger consolidation under FIN 46 on DP&L's books, it shall provide a written justification to the State Agencies and their Independent Consultant, however, so that the State Agencies may review that determination. As part of the review process, DP&L, the State Agencies and the bidder shall explore whether the structure of the proposed generation entity or PPA can be modified to prevent consolidation under FIN 46 on DP&L's books, as an alternative to disqualification. (Unanimous).

89. ***Site Control***. DP&L proposed that each bidder demonstrate that it had identified a site for capacity, and that if the bidder did not own the site at the time it made its bid, that it it its ability to acquire or secure the site by providing a purchase option or binding letter of intent from the site owner. Bluewater commented that for offshore wind projects, this requirement should be treated as satisfied if the bidder demonstrated the feasibility of obtaining permits and licenses and provided copies of requests from the bidder to agencies beginning the permitting of specific offshore sites. DP&L opposed this standard as inadequate.

90. The IC noted that rules for acquiring control of offshore wind sites were still being developed by the Minerals Management Service pursuant to the Energy Policy Act of 2005. Consequently, it was not clear what information the developer of an offshore wind project would be able to provide regarding site control. Thus, the IC recommended Bluewater's suggested standard as a reasonable way of determining whether an offshore wind project had reached a sufficient level of development to be considered on its merits. The IC also agreed that other projects should provide a binding letter of intent, but that a bidder be given a short cure period if clarification of rights under such a letter of intent is needed.

91. We agree with and approve the IC's recommendations for the reasons stated above. It would be impossible for an offshore wind project to provide DP&L with the information it requires simply because an offshore wind project can never own the site on which its project will be located. Until the Minerals Management Service issues rules for acquiring control of offshore sites, and in keeping with our goal of encouraging the greatest amount of participation consistent with the strictures of the EURCSA, we believe Bluewater's proposal as recommended by the IC will provide sufficient information to assess whether the offshore wind project should be considered on its merits. (Unanimous).

92. ***Permitting Schedule and Engineering Study.*** DP&L proposed as a threshold requirement that the bidder submit a reasonable schedule for acquisition of all necessary permits and demonstrate its ability to comply with all applicable environmental laws and regulations. No party commented on this proposal and the IC agreed that it was reasonable. The IC also recommended including in the schedule a complete development and construction schedule. We believe that the IC's recommendations are reasonable and approve them. (Unanimous).

H. Security Requirements

93. ***Pre-Operational (Development) Period.*** For Developmental Security, DP&L proposed that the seller provide a letter of credit ("LOC") in the amount of $50/kW of capacity on the PPA's execution date. Within 15 days after the Effective Date (after all conditions precedent to the Effective Date including regulatory approval have occurred), DP&L would require the security to be increased to $100/kW, according to its proposed Instruction to Bidders (§3.4.1). The IC noted that the seller's PPA exposure could exceed $100/kW before the Initial Delivery Date because Delay Damages may become due during the development period. If Delay Damages are not paid as due they may be withdrawn from the $100/kW security. Upon withdrawal, DP&L required the full amount of security to be replenished (an "evergreen" provision). Thus, the maximum developmental period security was $100/kW plus the maximum amount of Delay Damages, which the IC calculated as $85.15/kW ($0.2333 per kW-day for one year). DP&L also proposed that whenever the construction period and the expected delivery period overlapped, the seller would be required to maintain both Developmental Security and to post Operational Period Security.

94. Bluewater objected to these requirements as too high, indicating that for renewable projects, security in the $30-$60/kW range had been sought in other procurements. Likewise, SCS complained that $100/kW was too high.

95. The IC concluded that the level and structure of DP&L's proposed Developmental Security fell within a reasonable range. The IC found, based on its analysis of other recent RFPs, that DP&L's proposed $100/kW security was reasonable, as it had seen security ranging from $50-$200/kW. The IC stated that in some cases, the Developmental Security secured the maximum amount of potential delay damages while in others (such as DP&L's), additional delay damages would come due upon the occurrence of delays. The IC

observed that DP&L's proposed Delay Damages were higher than in other RFPs, where the range had been between $0.17-0.20/kW.

96. However, the IC did recommend two modifications to the proposed Developmental Security. First, due to lower capacity factors and generally lower required security in the industry, wind projects should only pay 40% of the normal required security for baseload and other projects (e.g., $40/kW for Developmental Security, 40% of the associated delay damages, and 40% of the IC's proposed cap on Operational Period Security). Second, in the event of delays causing the planned development period to extend beyond the Guaranteed Initial Delivery Date, there should be no doubling up on security; rather, Operational Period Security should only be applicable once the Initial Delivery Date has actually commenced.

97. DP&L objected to the IC's proposed modifications. DP&L claimed that the IC had recommended that a bidder having an investment grade guarantor could provide a parent guaranty instead of a LOC to provide the requisite credit support, and that this would weaken the credit and security arrangements. The IC stated that it did not intend to propose such a modification, but understood how its markup of the RFP could be construed that way, and so clarified its recommendation to provide that the required form of security should be a LOC or some other security acceptable to DP&L.

98. DP&L also objected to the IC's differentiated security for wind projects, arguing that it was discriminatory and could lead to projects claiming lower capacity factors to reduce their security requirements. The IC clarified that its proposal would also apply to other intermittent renewable energy projects such as hydro and solar. Moreover, the IC explained that its recommendation was not discriminatory because it was based on the different characteristics of these types of projects (lower levels of energy produced and UCAP, and market levels for

security that were generally lower than conventional projects). Last, since the amount of security would be based on nameplate capacity, there would be no incentive for a bidder to lower the capacity factor that it claimed its project can provide.

99. Last, DP&L also indicated that it did not intend to require a doubling up of security payments. It clarified that the Operational Period Security does not commence until the plant comes on line and Delay Damages would end concurrent with the plant operating,

100. Even though DP&L's proposed Instructions to Bidders specified the required security as $100/kW, DP&L notes that its proposed Key Commercial Terms of Power Purchase Agreement (term sheet) provides that one year's worth of Delay Damages also be provided in security shortly after the Effective Date, which would raise the total required Developmental Security to approximately $185/kW. The IC noted the discrepancy between DP&L's proposed Instructions to Bidders and term sheet in its Final Report and indicated that based on guidance it had received from DP&L's RFP Manager, it had understood that DP&L had proposed $100/kW as Developmental Period Security (i.e., a seller would not be required to set aside security for a year's worth of Delay Damages.

101. We agree with and approve the IC's recommendation with respect to Developmental Security. Security provisions come at a cost to potential bidders, which will be reflected in their bid prices. High levels of security may also deter potential bidders from bidding. We believe that the IC's recommendation, which is primarily based on DP&L's security proposal contained in its proposed Instruction to Bidders, strikes the right balance between protection of ratepayers, commercial reasonableness, and potential impact on bid participation and pricing. (Unanimous)

102. ***Operational Period Security.*** DP&L proposed that it should not have to post security even in the event of a downgrade. As for the seller's collateral requirement, DP&L proposed two years of replacement power costs calculated as the expected PJM RPM capacity value (or a mutually agreed upon equivalent) plus NYMEX Henry Hub forward energy price times an 8,000 Btu/kWh implied heat rate. DP&L reserved the right to change the heat rate subject to the nature of the PPA. The collateral requirement would not be subject to any maximum limitation or cap. DP&L proposed that at least 10% of the required security be in the form of a LOC. Based on the seller's/guarantor's credit rating and a specified percentage of its/their net worth, a portion of the requirement could be unsecured. In the event of a downgrade involving the seller/guarantor, DP&L proposed that the credit requirements be re-evaluated according to overall formulae. Additionally, DP&L required the seller to grant DP&L a second lien on the project.

103. NRG and SCS argued that Operational Period Security should be based on the normal cover theory of damages: the difference between the proxy price for replacement power and the contract price. Bluewater contended that the required security was excessive and requested a lower requirement for wind projects; that DP&L should be required to post security; that a second lien be used in lieu of a LOC or that unsecured credit be exclusively relied upon, and that there be a cap on required security. The DPA recommended that security requirements be reduced to something more conventional. NRG stated that the required security for its proposal would total nearly $500 million, which would be extremely problematic..

104. The IC found that proxy formulae for the replacement power cost in determining Operational Period Security were not unusual, but recommended applying the normal theory of cover damages. Thus, the formula would calculate net replacement costs as the positive

difference between the proxy market price and the PPA contract price – which was apparently what DP&L had actually intended.

105. The IC, however, took issue with DP&L's proposal that the required Operational Period Security be uncapped, finding that a cap was necessary to prevent the operation of the formula from reaching burdensome amounts. The IC proposed a $200/kW cap (which did not include the value of a subordinated lien on the project) based on its review of other recent RFPs, while taking into consideration the types of projects most likely to bid and the participation of bidders that are not investment grade. The IC stated that the $200/kW cap might be insufficient to cover damages over a two-year period if market prices are considerably higher than the PPA price, and in that circumstance a second lien would likely have considerable value. To ensure that a substantial portion of this value would be available to DP&L but not in a manner that was likely to adversely affect generators, the IC recommended limiting a seller's ability to leverage the project by more than 70% with lenders that have senior security interests. The IC suggested that a seller with an investment grade parent could provide a parent guarantee capped at the $200/kW level once the Initial Delivery Date was achieved. A seller without an investment grade parent would be required to post the full $200/kW in the form of a LOC or other security acceptable to DP&L.

106. The IC observed that wind and other intermittent renewable energy projects would only be required to post security of $80/kW, which it viewed as commercially reasonable in the context of DP&L's RFP based on the lower capacity factors of these projects, the lower amounts of UCAP provided, and industry practice. Further, while the IC believed that a second lien could provide valuable security, it should be seen as supplemental rather than primary

security. Finally, the IC did not believe that it was necessary for DP&L to post security, finding that that requirement would impose additional costs on DP&L and perhaps the SOS customers.

107. We agree with and approve the IC's recommendation that Operational Period Security be capped at $200/kW and at $80/kW for intermittent renewable energy projects. We are sympathetic to the claims of participants that this required security is on the high side, but none has argued that it is commercially unreasonable. In light of our decision not to require bidders to be investment grade and that Operational Period Security will be capped (both of which DP&L opposed), we believe that it would be reasonable to require security on the higher side in this context. While we are not unmindful of the sensitivity of these issues from DP&L's standpoint as the SOS provider, we reject the position that Operational Period Security should be uncapped because such a provision is not prevalent in the industry for long-term contracts and, if included, we believe it is likely that bid participation would be impaired because of the negative effect such a provision may reasonably have on financing. (Unanimous)

I. <u>Term Sheet</u>

108. As a threshold requirement, DP&L proposed that bidders agree with the Term Sheet included in the proposed RFP, which contains terms that DP&L called non-negotiable. The IC questioned this requirement, especially as to some of the specific terms and conditions. Even so, the IC did not believe that failure to agree to any term or condition in any manner should be the basis for automatic rejection; rather the IC proposed that changes proposed by a bidder should be a cause for rejection only if DP&L and the State Agencies' Independent Consultant agreed that those changes, taken as a whole, would "effect a fundamental restructuring of the risk allocation" set forth in the RFP and were therefore unacceptable, and the bidder failed to refused to withdraw those changes after being so notified.

109. DP&L contended that the "fundamental restructuring of the risk allocation" standard was too high a bar and would be difficult to administer. The IC agreed to an extent, noting that key commercial terms (level and amount of required security, liquidated damages) should be non-negotiable if there was a reasonable degree of comfort that they were commercially reasonable. The IC was comfortable that its proposed terms were commercially reasonable and supported their being non-negotiable, but did not have the same comfort with DP&L's proposed terms (such as the lack of a cap on Operational Period Security). The IC further disagreed that any proposed changes to the language of the term sheet should result in automatic disqualification.

110. We agree with the IC on this issue. As we have repeatedly stated, we view our goal at this early stage of the proceeding as opening the process up to as many potential bidders as possible. We believe that making all terms in a term sheet non-negotiable defeats that goal. While we agree that some terms should be non-negotiable, we do not believe that a bid should be disqualified merely because it differs from DP&L's proposed terms in some manner. We support reasonable flexibility in the conduct of the RFP. (Unanimous).

J. Bid Evaluation Methodology

1. Scoring Methodology and Its Use

111. DP&L proposed a scoring methodology by which each project would be scored pursuant to various categories (or subcategories) of price and non-price factors, after which the total points would be totaled and combined for a final score. The bid receiving the most points would be the winning bid, which DP&L would insert into its IRP evaluation. DP&L proposed 60 points for price factors (20 of which were for price stability) and 40 points for non-price factors (including environmental considerations, fuel diversity, technology innovativeness and

reliability, and proposed changes to a standard form PPA). No party opposed an evaluation system resulting in a single score that would determine the winner, although several parties challenged the points assigned to certain categories.

112. The IC noted that weighting the scoring categories in an RFP was always difficult because each RFP usually had several objectives. Here, in the IC's view, three considerations underlay the desire to seek a long-term purchased power contract from new in-state generation:

- providing Delaware residential and small commercial customers with the opportunity to stabilize their rates at attractive or acceptable levels and terms and conditions ("Economics");

- supporting generation projects that will benefit or mitigate impacts to the state overall and diversification for DP&L's SOS customers (environmental impacts, fuel diversity, technological innovation) ("Favorable Characteristics"); and

- contracting for a new project that has a high likelihood of being built, thereby providing economic and environmental benefits (financing plan, site development, operation date certainty, reliability, bidder experience) ("Viability").

113. The IC stated that it may not be the case that the project receiving the highest combined score would necessarily be the "best" project. Thus, the IC stated that a project should score well (or at least acceptably) in each of these three "supercategories" (economics, favorable characteristics, and viability). Because the State Agencies would be making the final decision based on the RFP criteria in accordance with the EURCSA, and the simple addition of points for those criteria may not fully capture the best option, the IC believed that some judgment should be permitted, and recommended evaluating the bids received on both an overall score and with respect to the component score in each of the three supercategories.

114. DP&L objected to the this approach, arguing that it represented a second level of threshold criteria and injected too much subjectivity into the evaluation process. The IC disagreed, noting that point scoring systems are not infallibly precise, and with four state

agencies making the determination(s) based on complex analyses and considerations, it was reasonable to allow the exercise of some judgment within the context of the point system. The IC concluded that the supercategory approach provided a rational way of ordering the various price and non-price factors and would assist DP&L and the State Agencies' Independent Consultant in evaluating the bids and the State Agencies in making their decisions.

115. We agree with the IC and approve the supercategory concept. We believe that this will provide the State Agencies and their Independent Consultant with flexibility and judgment, rather than marry us to the results of a straight addition of the numbers. Where, as here, the bids will necessarily be complex and reasonable minds could differ on the number of points within a category that a particular project should be awarded, we prefer to have the flexibility to go outside the bare numbers if the State Agencies think that would be appropriate. (Unanimous).

2. <u>DP&L Affiliate Issues</u>

116. The EURCSA provides that DP&L may propose a self-build project, and that DP&L affiliates may submit bids in the RFP process. 26 *Del. C.* §§1007(b)(3), (d)(2). The RFP suggested that DP&L and/or an affiliate may submit proposals that would be evaluated under the same process and factors as all other proposals and would not receive favorable treatment. The IC noted that the ability of DP&L and/or an affiliate to bid raised concerns about self-dealing and fairness in the evaluation process, and that from an evaluation standpoint, it would be preferable for DP&L to bid through an affiliate since that bid would be on a more equal footing with third-party bidders (although even these circumstances self-dealing concerns would remain). To assuage concerns about self-dealing, the IC proposed the following procedures:

- Any proposal by a DP&L affiliate should be submitted to DP&L and the Commission at the same time, and should be submitted one day in advance of all other bids.

- Personnel working on an affiliate proposal or DP&L self-build proposal should be prohibited from working on/communicating with any personnel working on the RFP or the RFP evaluation regarding the RFP or RFP evaluation.

- All of the RFP requirements (including security) shall apply to any DP&L affiliiate that submits a bid, in addition to those that apply specifically to DP&L affiliates.

117. The IC explained that the day-in-advance mechanism was used in other states to minimize concerns about self-dealing. DP&L proposed that affiliates be required to submit bids on December 21 (one day before all other bids are due). Bidders concerned about self-dealing would have the option to submit their bid before or after December 21.

118. We agree with and approve the IC's recommendation, with the clarification that the prohibition against personnel working on a DP&L self-build project working with or communicating with personnel working on the RFP bid evaluation would apply only for a DP&L self-build project under active development. (Unanimous).

3. <u>Price Evaluation Methodology</u>

119. As mentioned previously, DP&L proposed that price factors comprise 60 of the available 100 points, with 40 points for lowest expected price and 20 points for price stability. DP&L described the economic analysis as a multi-step process involving the impact of the bid price on SOS customers (including a direct evaluation of the contract price and an indirect analysis of the effect that the generating unit should have on the overall market price for power in Delaware); other cost factors such as the impact on transmission costs and losses associated with the generation option, an imputed debt offset, and a potential loss component based upon the probability of default. Bids would also be evaluated for their risks to customer costs based

on an assessment of the level of price stability associated with the bid pricing structure. Finally, the top bid(s) would be evaluated within the framework of the IRP to ensure that a full consideration of costs had been addressed.

120. The IC stated that the RFP generally outlined the cost components of the evaluation, but contained little information about the methodology and models used in the evaluation. For example, the IC explained that there was little information about the calculation of the price stability component and it was apparent, based upon discussions with DP&L and its consultant, that the methodology had not been highly defined or refined. Nevertheless, the IC went on to discuss the price evaluation process and the conceptual intent of the evaluation, the modeling methodology, and the application of the models underlying the methodology.

121. ***Point Allocation.*** Several of the participants challenged the price category point allocation. SCS argued that the approach should be revised to allocate points equally among the criteria set forth in the EURCSA. Thus, no points should be allocated to price rank and 20% of the available points should be allocated to price stability. Bluewater contended that lowest price should not be a consideration alone because the EURCSA did not stipulate "lowest cost."

122. The IC found the 60/40 division of price and non-price points to be a typical allocation, noting that common industry practice was to weight price factors between 50-70% and non-price factors between 30-50%. In most cases, lowest price was the primary selection criterion, with risk factors included in the final evaluation in some processes. In some RFP processes, the IC observed that price stability is a non-price factor.

123. The IC recommended DP&L's 60/40 allocation, subject to the supercategory evaluation already discussed (and approved). The IC further recommended the following

allocation of points within the price category: Price Stability – 20; Price – 33; Exposure – 6 (which encompasses contract size and bidder creditworthiness); and Contract Terms – 1.

124. ***Components of Price Factor Evaluation.*** DP&L stated that it would evaluate all proposals based on price and operational performance factors through a simulation of the project's impact on the costs paid by SOS customers. This evaluation included the following components (among others): PPA capacity and energy price; Residual SOS Cost Impact; T&D project impact; transmission losses; imputed debt offset; and loss under probability of default. DP&L intended to calculate a levelized cost per kWh as the basis for calculating the cost of each bid. Additionally, DP&L planned to calculate the dollar magnitude of risk for SOS customers. Price Stability would be captured in the Uncertainty component of the PPA energy price, Residual SOS Cost Impact and Loss Under Probability of Default. DP&L was also considering conducting a standard deviation assessment for estimating the stability of each bid received.

125. ***a. PPA Capacity Price***. DP&L requested bidders to provide a levelized capacity price in dollars per kW/month; variable capacity payments were unacceptable. Capacity could only be provided from the bidders' projects and must be reliable as determined by whether it qualified for UCAP in PJM. All bids would be evaluated at the target EAF specified by the bidder (or a substitute if the specified EAF is deemed unrealistic).

126. The IC disagreed with the requirement that bidders bid a fixed levelized capacity price. It noted that portions of the capacity price may not be indexed to general inflation indices or specific capital cost components such as steel. The IC stated that many RFPs for long-term unit contingent power allow a portion of capacity prices allocable to fixed O&M costs to be indexed to a general inflation index, a labor cost index, or both, but typically have not allowed for indexing to capital cost components. This approach has been the dominant one in prior RFP

processes, but the IC believed that there was justification for allowing longer lead time, capital intensive technologies (such as coal-fired and offshore wind projects) to include some significant indexing in bid capacity prices. The IC noted that in the past few years, the costs of steel, labor and specialized metallurgical components have increased dramatically, leading to difficulties in securing an Engineering, Procurement & Construction ("EPC") contract for such resources. This price risk has led to bidders bidding higher fixed capacity costs. If some of the risk could be mitigated through indexed pricing, a bidder could price more aggressively. The IC observed that some utilities had begun to address this issue by allowing bidders the option of either bidding a fixed capacity price or indexing the variable portions of its capacity cost by known indices that match the cost components. As an example, the IC explained that a bidder may index components of the capacity price from the base period to either the time of execution of the EPC contract or to the in-service date of the project. Components of the bid tied to steel prices could be indexed to a steel index, while other components could be indexed to an inflation index. Thus, the IC recommended that a portion of capacity prices be indexed to general inflation indices (for recovery of fixed O&M expenses) and that no more than 15% of the capacity price be indexed to a steel index from the time of bid submission until the bidder executed its EPC contract, but no later than two years after contract signing (after that, capacity prices would be fixed), subject to a cap.

127. We agree with and approve the IC's recommendation, which we believe will widen the pool of potential bidders, subject to the strictures of the EURCSA. As noted, that is our goal throughout this process. (Unanimous).

128. ***b. PPA Energy Price.*** DP&L proposed to pay bidders for the energy component based on the price offered in cents per kWh, which may consist of a starting price plus an

escalator or other means of demonstrating the energy price level that DP&L will pay for energy. Bidders may index their price to a publicly available index but must specify which one. The IC stated that DP&L should be more explicit with regard to the allowable indices, assuming that DP&L would accept known and measurable indices to include in an energy price formula. The IC stated that bidders should also be allowed to propose an energy price component reflective of variable O&M costs with an applicable index (usually inflation); they should also be permitted to include fuel indices in their price bid, with the energy charges related to a specific heat rate at specified load levels (based on a heat rate curve). The IC found that this would allow bid prices to relate more closely to costs, which would allow for more aggressive bidding.

129. No party objected to the IC's recommendation. We agree with it and approve it. (Unanimous).

130. ***c. Residual SOS Cost Impact.*** This component addresses the impact that each project is projected to have on total system SOS costs. It could be positive or negative depending on the proposal's cost structure and operating characteristics and the project's impact on PJM market prices. It captures two impacts. The first is the displacement impact associated with the output from the new unit on existing SOS. Since DP&L is assuming that SOS could be acquired at market price, any residual power could be sold (or acquired) at projected market prices. The second impact is the potential effect on market price of the new generation resulting from this RFP. DP&L stated that the residual SOS cost impact would be estimated using computer models to simulate its system with both existing and new units. The residual SOS cost impact would be determined by combining a project's impact under a base scenario with high and low price scenarios to determine the effect on prices that are higher and lower than those anticipated. DP&L will also take price variability into account.

131. The IC noted that other utilities have used a similar approach for assessing system production cost impacts associated with new generation options, and that while DP&L's proposed methodology was not conceptually problematic, the IC recommended that DP&L finalize and identify the proposed methodology for assessing price stability associated with the residual SOS cost impact. The IC believed it was important for DP&L to articulate clearly to bidders the methodology to be used, especially given the importance of price stability as an evaluation component.

132. We agree with and approve the IC's recommendations. Again, we believe that the best approach at this stage of the proceedings is to make the process open to as many bidders as possible. DP&L, after consulting with the IC, should provide potential bidders with additional information regarding the critical component of price stability, at an early date prior to the receipt of bids. (Unanimous).

133. ***d.& e. T&D Project Impact/Transmission Savings or Losses.*** The T&D project impact represents the savings or expenses to DP&L resulting from a project by allowing DP&L to defer or causing it to advance planned T&D system capital improvements. The computer-modeled analysis will assess the benefit or cost of other transmission projects that will be deferred or accelerated as a result of the proposed project, the impact on transmission facility loading and possible violations of thermal limits using a four-step process: (1) establish baseline transmission conditions; (2) determine appropriate transmission projects to mitigate identified overloads; (3) assess the impact of the proposed generation on DP&L's transmission system; and (4) assess the financial impact of each proposed generation option on the transmission system. Any incremental network transmission cost or savings will be added to the proposal's cost for purposes of the price evaluation. According to DP&L, the evaluation of transmission impacts

will be preliminary and will be used only for evaluation. The RFP requires bidders to provide information on project location, interconnection point, voltage level and an application for a PJM feasibility study with their NOIBs. DP&L will also measure the value of energy saved or lost as a result of project operations as a price factor.

134. NRG recommended that DP&L's quantitative estimation of T&D project impact be limited to a five-year duration and that the models used for estimating those impacts be consistent with PJM's models and assumptions. Additionally, NRG argued that only the portion of the T&D impact associated with the RFP process should be considered in evaluating the bid for any project that will sell part of its energy and capacity in the wholesale market. DP&L responded that it saw no basis for limiting the analysis of transmission impacts to five years.

135. The IC stated that it is typical in competitive bidding processes for utilities to assess the impact of proposals on their system transmission costs as a major cost component, although the approach for assessing transmission cost impacts may differ depending on the market structure in different regions of the country. The IC found that DP&L seemed to have developed a detailed process and methodology for assessing T&D system impacts integrated within the PJM market. The IC noted that other utilities had limited their assessment of such impacts to five years, but that if a utility had the ability to evaluate such impacts over a longer term that approach would be preferable. Thus, the IC supported DP&L's plan of analysis.

136. We agree with and approve the IC's recommendations for the reasons stated in its report. We believe that if it is possible to do so (and apparently it is possible here), T&D impacts should be evaluated over a longer time period. The contracts that will be entered into as a result of the RFP process will be from 10-25 years in duration, and therefore limiting the analysis to

five years would not, in our view, provide as accurate an assessment of the costs or benefits associated with a particular project. (Unanimous).

137. ***Imputed Debt Offset.*** DP&L proposes to assess the incremental equity amount to be equal to, at a minimum, 50% of the net present value ("NPV") of the bid's capacity payment. A percentage of the energy price may also be included if DP&L concludes that a portion of the bid's energy component would be imputed as debt by rating agencies in their assessment of DP&L's creditworthiness. The methodology that Standard & Poor's ("S&P") uses for calculating the amount of imputed debt to include on a utility's balance sheet is generally based on a risk factor ranging from 30-50% based on the perception of the risk to the utility for recovering PPA costs. S&P states that a 50% risk factor is appropriate for long-term commitments, assuming adequate regulatory treatment, including recognition of the PPA in rates. A 30% risk factor may be appropriate for utilities with a supportive regulatory body having a precedent for timely and full cost recovery of purchased power costs. S&P considers lower risk factors of 10-20% for distribution utilities where recovery of certain costs (including stranded costs) has been legislated.

138. NRG and SCS recommended that the Commission eliminate the imputed debt adjustment. NRG argued that DP&L's assumption that its debt rating would necessarily suffer as a result of the PPA was incorrect. It noted that in assigning debt ratings, the rating agencies considered the totality of a utility's financial position, and PPAs and other long-term contracts were only one factor evaluated in that process. NRG contended that DP&L had not shown that entering into a PPA would impose an actual cost on it, nor had it shown that such a cost could be represented as an incremental amount of equity required to return its balance sheet to pre-existing levels. Additionally, NRG asserted that in assigning credit ratings, the rating agencies

are primarily concerned with the utility's ability to service its debt. If PPA costs are reasonably assured of being passed through in retail rates, the agencies will likely be less concerned with the PPA. NRG observed that other states' regulatory authorities had held that a utility could file a rate case in the event its credit was downgraded and could request remedies such as an increase in the return on equity, and had declined to adopt automatic and formulaic adjustments in evaluating PPA proposals. Finally, NRG contended that including the imputed debt offset in the RFP appeared to be an attempt to establish DP&L-supplied generation as the preferred choice since the offset would hamper all other bidders.

139. Bluewater stated that it understood DP&L's concern but requested clarification regarding the application of the imputed debt offset to a wind project.

140. The IC called the imputed debt offset one of the most controversial factors in the competitive bidding environment. It explained that rating agencies treat PPA fixed costs as debt on a utility's balance sheet, which requires the utility to offset the higher financial leverage associated with the imputed debt by raising equity to rebalance its capital structure. Since equity costs more than debt, utilities contend that the debt-like aspects of PPAs impose a cost that must be accounted for in the bid evaluations. Independent generators, on the other hand, argue that there is no empirical evidence to support the utilities' claim that PPAs cause them to experience greater financial cost and risk than if the utilities built the generation themselves. They believe that applying an imputed debt offset skews the bid evaluation in favor of the utility's self-build option. The same concern may apply where the alternative to a long-term unit contract is a one- to three-year PPA, which generally raises fewer concerns with the rating agencies.

141. The IC further noted that there was no consistency among state regulatory bodies regarding the imputed debt offset. Only nine states had addressed the issue, and only a few of

those explicitly permitted such an adjustment. The states varied with respect to the level of the risk factor, the appropriate time in the evaluation process to address the adjustment, and whether the impact should be accounted for in an RFP process or in a cost of capital proceeding. The IC observed that the Oregon commission had recently ordered that debt imputation should not be used to determine an initial "short list," and that a utility would have to obtain an opinion from a rating agency to substantiate its claims of the necessity for the adjustment.

142. The IC identified several alternatives for consideration. First, the Commission could reject such an adjustment in the RFP process, given that the effects were uncertain and the quantitative methodology would need to be defined. Second, the Commission could calculate an imputed debt offset outside the normal bid evaluation process under a lower risk factor (e.g., 30%) to reflect the cost recovery mechanisms for DP&L in Delaware and determine whether the adjustment affected the evaluation results. The imputed debt offset would be used to determine the impact on the ranking of bids based on the size of the adjustment. Third, the Commission could use the adjustment consistent with DP&L's methodology as a component of the bid evaluation. Fourth, the Commission could apply the adjustment only if comparing the bids to shorter-term purchases, not to self-build options. (The rating agencies believe that self-building is also risky, and calculating different adjustment factors for each resource type is very subjective). Finally, the Commission could approve the imputed debt offset as DP&L proposed.

143. SCS contended that imputed debt should not be considered in the bid evaluation. NRG took the same position, although noting that the Oregon commission's process might be meritorious. DP&L opposed using a 30% risk factor in the evaluation process, arguing that 50% was consistent with S&P's methodology and should be used as the base case.

144. The IC supported the second alternative, whereby an imputed debt offset would be calculated but used for sensitivity purposes, as opposed to an explicit direct impact on the bid evaluation process. The IC opined that given the EURCSA's structure and that the Commission was likely to order DP&L to enter into a PPA and establish a rate recovery mechanism, it was probable that the risk factor would be lower than 50%. The IC further recommended that DP&L include a spreadsheet in the RFP describing its imputed debt offset methodology and a means to calculate the impact of a particular proposal. Since the State Agencies would ultimately be making the decision as to which resource to select (if any), the IC concluded that it was appropriate to use a risk factor that pertained to DP&L's situation: a distribution utility that will enter into a contract as directed by regulatory agencies pursuant to legislation providing for recovery of the PPA costs in rates. It noted that S&P states that a 30% risk factor can be used for distribution utilities in a jurisdiction allowing for timely and full cost recovery, and in certain cases an even lower risk factor of 10-20% may be appropriate. Moody's also states that where there is a clear ability to pass PPA costs through to customers, it would not regard the PPA as having long-term debt-like attributes. The IC stated that these views from the rating agencies supported its recommendation. It further observed that its recommendation was consistent with treatment in other jurisdictions, where the pertinent range for considering imputed debt has been 0-30%. The IC concluded that it would be reasonable for the State Agencies to request DP&L to provide a report from S&P should imputed debt significantly influence bid ranking and selection.

145. We agree with and approve the IC's recommendation. The EURCSA provides that DP&L will be permitted rate recovery of PPA costs. In addition, DP&L is a distribution utility. Based on the written guidance provided by S&P and Moody's and the precedents established in other jurisdictions, we believe it is reasonable not to incorporate an imputed debt

offset in the economic evaluation but to include a 30% risk factor in a sensitivity analysis. We note that a 30% risk factor appears more apt than a 50% risk factor in light of the relevant EURCSA provisions and DP&L's role as a distribution utility as opposed to a vertically integrated utility. We also do not believe that it would be appropriate to include the imputed debt offset as a factor in the bid evaluation, as we believe this could provide a DP&L self-build option with an advantage that may not be justified. Thus, we agree with the IC. (Unanimous).

146. ***Loss Under Probability of Default ("LUPD"); Exposure.*** This price factor is intended to address the potential economic cost to DP&L's end-use customers if the seller should default. The analysis assesses the credit risk of the bidder's proposal using measurements of the default probability (based on credit quality and the likelihood of default based on a bidder's credit rating), credit exposure (based on contract size and pricing relative to forward market prices), and recovery rate. Overall exposure will be assessed as the NPV of the exposure to SOS customers. This analysis is a form of credit value at risk analysis.

147. NRG raised several concerns about this component. It argued that the calculation of the LUPD was a complex process involving numerous factors that would influence the final results, including the default rates by credit rating, time at which the bidder defaults, the timing and level of recovery, and others. It contended that such possible contingent costs as these could not be reliably measured over the lengths of time DP&L was proposing. It explained that for each bidder, DP&L was proposing to (1) estimate the likelihood and timing of default over the PPA's life; (2) estimate the cost of replacement power beginning at the time of default and running through the PPA's end; (3) estimate the offsetting economic value of its security and any claims that may be realized through legal processes; (4) combine all the probabilities and loss or gain values mathematically (by means of a convolution approach) and (5) discount everything

back to a present value figure that could be compared among all bidders. NRG contended that DP&L was trying to perform a quantitative "Expected Loss and Recovery" analysis over time periods up to 30 years and possibly involving a number of disparate generating technologies.

148. The IC expressed "major concerns" regarding the usefulness and appropriateness of the LUPD analysis. It explained that the methodology purported to assess the SOS customers' exposure under a PPA; a lower exposure means a higher score. But, the IC found, two of the key components of the analysis did not work well in this context. First, the amount of credit exposure was based on the mark-to-market exposure, which is a function of the market price minus the PPA price. If the PPA price is too high relative to the market price, there is relatively little or lower credit exposure. Thus, the IC concluded that this analytical tool appeared to favor projects with high pricing. Second, the IC observed that the default rate is not based on the probability that a seller will default on its PPA obligations, but rather solely on the seller's/guarantor's credit rating and the probability that companies with that credit rating default on their obligations, as determined by the rating agencies. The IC was unaware of any other RFP process that included such a price factor.

149. Based on these reasons, the IC recommended eliminating this factor. However, it was sympathetic to the reason DP&L included it (there should be some measure of SOS customer exposure based on bidder creditworthiness and other factors), and so recommended that 6 points be allocated to a category called "Exposure." The key factors in this category would be contract size (larger contract size creates greater risk), capacity factor and dispatchability, bidder creditworthiness and contract duration. The IC explained that any contract of 200 MW or less for 10 years with an investment grade seller would maximize its score in this category, whereas a 400 MW baseload project for 25 years, with little or no ability

to ramp down to less than full load once it is on line, and a non-investment grade seller, would score zero points. Points would be allotted in between based on the factors identified above. Bidders of large projects could bid up to the maximum contract size, but the added exposure above that associated with a 200 MW baseload project would be considered as creating additional exposure for SOS customers. The IC called DP&L's proposal overly complicated, and believed that it would detract from the credibility of the bid evaluation in light of the short time for evaluating bids. The IC noted that its proposal for reflecting exposure was more straightforward and verifiable, easier to implement, and better accounted for risk factors.

150. We agree with and approve the IC's recommendation. DP&L's proposal is extremely complex, as NRG's position demonstrated. Given that the State Agencies have only a short period of time in which to evaluate bids and make a selection, we believe that it is more prudent to assess the SOS customers' potential exposure in the manner that the IC has recommended. It is indeed more straightforward and simpler to implement. (Unanimous).

151. ***Price Stability Evaluation.*** DP&L proposed that 20% of the overall weighting be allocated to price stability. It proposed to assess both the stability of the project's price stream (energy costs) and the price variability associated with the Residual SOS Cost Impacts (discussed earlier). It also proposed assessing the variability of the LUPD component in its evaluation of price stability (which we have previously rejected). The IC observed that although the RFP provided some discussion of the components that DP&L would consider in assessing this factor, there was nothing regarding the quantitative metric DP&L would use to calculate the price stability associated with each project (i.e., standard deviation of the price stream) or the use of that metric for calculating the points associated with each bid. DP&L subsequently provided a proposed four-step process for analyzing the bids' price stability attributes. We agree with the

20% weighting for price stability, and direct DP&L to provide a description of the process for assessing the bids' price stability to bidders at or shortly after the pre-bid conference after conferring with the IC. (Unanimous).

152. ***Economic Evaluation Methodologies and Modeling Issues (Test Bids).*** The IC stated that the economic evaluation methodology was an important aspect of the RFP process that generated several issues associated with the economic evaluation and modeling of bids:

- The appropriate models and methodologies for evaluating the proposals requested, given the types of products and resources solicited;
- The integration of the RFP with the IRP process;
- The appropriate methodology or metric (i.e., total system PVRR, $/kW, $/MWh) for converting the economic analysis results into a price score or points for comparison with non-price factors;
- The evaluation of bids with different terms;
- The evaluation of bids with different capacity and energy amounts relative to the amount of capacity and energy required;
- The basis for evaluation and selection; and
- Consistency of the input assumptions between the RFP and the IRP.

The IC observed that utilities had used a wide range of models and methodologies to assess bids; a common approach was for the utility to use the same models both for developing the IRP and for evaluating bids. This approach generally involves sophisticated production cost or generation expansion models that allow the utility to perform a system-wide assessment, including direct and indirect costs (that is, benefits associated with the displacement of other resources based on system dispatch) for the bids received.

153. DP&L stated that its consultant would assist it in preparing its IRP, and that the consultant would use its Integrated Planning Model ("IPM") and integrated data system as the

main analytical tool. The IC explained that the IPM model evaluated potential expansion options, including new capacity options, transmission builds, and demand side management. The model minimized system cost over the time horizon by assessing power plant dispatch for existing units, new entry options, grid operations and transmission considerations, and estimated forward zonal power prices in PJM and captured transmission, environmental and fuel constraints. The output projections for the model include power, fuel and allowance prices; asset values; dispatch decisions; capacity build decisions; emissions; compliance costs; compliance decisions; and plant retirement decisions. Although the IPM is the key tool in the evaluation, the integrated analytical framework also includes several models: GE-Maps for analyzing location-based marginal prices, congestion and losses; PowerWorld for evaluating the transmission grid, interface capabilities and critical contingencies; MANGAS for evaluating gas supply; and CoalDom for evaluating coal supply.

154. NRG raised several issues regarding the modeling methodology. First, it claimed that DP&L's methodology did not encourage transparency because DP&L had not identified the computer models to be used in the analysis. Second, NRG argued that DP&L must fully disclose all models and input assumptions in order that RFP participants can verify them. Third, NRG complained that using mathematical models beyond their range of reliable prediction may bias the selection process against long-term PPAs and the capital-intensive solid fuel, baseload projects that require long-term PPAs.

155. The IC met with DP&L and its consultant and reviewed the modeling methodology information. Based thereon, the IC stated that it appeared that the modeling methodologies were consistent with industry applications for both the IRP and RFP processes. The IC found that the fact that the analytical tools and framework would be applied to both the

IRP and RFP should ensure consistent evaluation results. The IC stated that it understood that the model would address the term and size issue for different bids by assuming that SOS contracted from the market would be used as the marginal resource. In cases of bids having a lower capacity level than required on a shorter term, the forecast of market prices based on the forward curve produced from the model will be used to meet the marginal requirements. Likewise, if some existing SOS contracts are displaced as a result of a contract, the power will be sold into the market at the market price. The IC found that this process was consistent with industry approaches and should provide consistent and reasonable results.

156. The IC noted that DP&L apparently intended to use levelized cost per kWh as the comparison metric, but it was unclear whether DP&L had actually settled on that particular metric. Thus, the IC found that it was premature to determine a scaling system to convert economic price scores to points. The IC recommended that the scaling system be determined no later than the bid submission deadline (December 21, 2006 for DP&L affiliates).

157. The IC recommended that "test bids" be established and evaluated to ensure that DP&L's evaluation process was consistent and effective and produced unbiased and consistent results. This process would include the IC completing all the bidding information requirements as any other bidder would and working with DP&L through the evaluation of the bids, including reviewing modeling operations and results. The IC explained that if there are any problems, it is better to find out before bids are received and evaluated. The IC planned to develop bids for several technologies, including a coal gasification project, a wind project and perhaps a gas-fired combined cycle plant to ensure that there are no biases favoring a particular option.

158. The IC reviewed the information included in the Bid Forms regarding proposal pricing and operational information requirements and found it consistent with the modeling

evaluation requirements. It noted, however, that the RFP did not request information on the proposed unit's targeted EAF even though this was an important component of capacity payment requirements. The IC observed that it was typical in other RFPs that the information for the utility's models be consistent with the information requested in the bid forms, and the IC modified the forms to achieve this consistency.

159. Furthermore, the IC noted that bidders may not accurately provide their pricing formulae, thus requiring the utility to seek clarification. If the utility has to do this, this can delay the evaluation process. The IC found that DP&L's request for pricing information and formulae was fairly general, with no specific pricing schedules or formulae for the bidder to complete. Thus, the IC provided more specific information requests in its proposed changes to the bid forms.

160. The IC opposed NRG's suggestion that DP&L's models and assumptions be fully disclosed and available to all RFP participants as contrary to general industry standards. The IC noted that it was rare for a utility to provide its models to prospective bidders, and when they have done so it is usually a spreadsheet-based model rather than a proprietary third-party model. In addition, the IC noted that requiring DP&L to provide the models to bidders would likely result in unnecessary delay in the process in light of the IC's involvement.

161. The IC also opposed DP&L's proposal not to provide the IC with anything until after its analysis was complete. It noted that the State Agencies are responsible for making determinations with respect to the bid evaluations in a legislatively-mandated timeframe. It would be difficult to fix a flawed methodology on an after-the-fact basis within the constraints imposed by the Legislature. Thus, the IC found that it was critical for the State Agencies through their consultant to fully understand the methodologies and assumptions used and have

the ability to ask questions and seek modification prior to bid submission, *not* after the bids have been reviewed and evaluated.

162. The IC explained that the objective of the test bid process was to assess the bid evaluation methodology in advance of bid submissions to gain perspective on the process and to verify the consistency, efficiency and reasonableness of the modeling methodologies. The IC stated that it was important for the integrity of the process that input assumptions and methodologies be confirmed prior to bid submission and that those assumptions and methodologies not contain any undue bias toward any source. The IC recommended that test bidding be conducted unless the IC agreed that there was not enough time to do so and the IC was given sufficient information and input to be comfortable with the bid evaluation process, methodologies and assumptions. The IC further recommended that DP&L choose a price evaluation metric so that a scaling approach can be determined. Finally, to assuage NRG's concerns, the IC recommended that DP&L either spend a significant portion of the bidder conference describing and explaining its bid evaluation methodology and process or that it provide more detail later after there is further refinement in the methodology and process. The IC explained that it was important for bidders to have a reasonable amount of information as to how bids will be evaluated and what information they must provide with their proposals.

163. We agree with and approve the IC's recommendations for the reasons discussed in the report. We do not believe that the information requested by NRG should be made available to prospective bidders given that it is proprietary material belonging to a third party. However, we do believe that bidders should know how DP&L plans to evaluate the bids it receives, and so we agree with the IC's recommendation with respect to the bidders' conference or later refinement. We also agree with and approve the IC's recommendation for test bidding.

If problems with the evaluation process are not discovered until after the bids have been received, we do not believe there will be sufficient time within the legislatively-mandated deadlines to resolve those problems. (Unanimous).

164. ***Input Assumptions***. These are items such as fuel forecasts, discount rate, market price forecast, inflation forecast, emissions cost, cost of new entrants and other factors. The IC understood that DP&L would project the market price forecasts internally within its proposed modeling analysis. The RFP, however, did not provide any information about the forecast for input assumptions. NRG commented that a mathematical model is only as good as its underlying assumptions and data inputs, and that the forecast of input assumptions could bias the results of the analysis if not consistently developed. The IC stated that it intended to closely scrutinize the input assumptions to ensure that there were no inherent biases in the forecasts of the variables and that they were reasonable. It noted that the test bid process would be valuable in assessing the reasonableness of the input assumptions and ensuring that there is no inherent bias. We agree with and approve the IC's recommendations. (Unanimous).

165. Finally, we agree with the IC and other parties that price is appropriately a factor in the evaluation of the bids; indeed, we believe it *must* be a factor. Given the situation that led to the genesis of the EURCSA (high SOS rates), we do not believe that the General Assembly would have intended the State Agencies to consider a new generation source in Delaware that would assure stable prices at the expense of those prices being extremely high. We understand the concern that environmental factors have not been given sufficient weight in the point allocation, but we further observe that there are 14 points explicitly allocated for Environmental Impact (an issue we will address *infra*) and that environmental factors also are addressed in the context of other issues (i.e., fuel diversity and price stability). Hence, we believe that

environmental factors will indeed be addressed in the bid evaluation beyond the 14 points that have expressly been allocated to them. But we also believe that in order to discharge our duties under the EURCSA, we must consider price as a factor. (Unanimous).

4. <u>Non-Price Factor Evaluation</u>

166. The EURCSA states that the proposed RFP shall set forth proposed selection criteria based on the project's cost-effectiveness in producing price stability, reductions in environmental impact, the benefits of adopting new and emerging technologies, siting feasibility, and terms and conditions concerning the sale of energy output from the facilities. The EURCSA directs the Commission and Energy Office to "ensure that each RFP elicits and recognizes the value of" the following:

- Proposals that use new or innovative baseload technologies;
- Proposals that provide long-term environmental benefits to the state;
- Proposals that have existing fuel and transmission infrastructure;
- Proposals that promote fuel diversity;
- Proposals that support or improve reliability; and
- Proposals that use existing brownfield or industrial sites.

167. The non-price factors fall within "Favorable Characteristics" and "Viability" supercategories. "Favorable Characteristics" include environmental impact, innovative technology, and fuel diversity. "Viability" includes operation date and certainty, reliability of technology, site development, bidder experience, safety and staffing, and project financeability. The IC recommended the following weightings, assuming 40 points for non-price factors:

Environmental Impact	14
Operation Date and Certainty	3
Innovation of Technology and Reliability	

a. Innovation b. Reliability	3 2
Fuel Diversity	3
Site Development	5
Bidder Experience, Safety & Staffing	5
Project Financeability	5

The IC recommended that the Contract Terms category be moved to the evaluation of Price factors and be reduced from 2 points to 1.

168. ***Environmental Factors.*** The RFP states that reductions in environmental impact (including emissions), impacts on water emissions and quality and land impacts will be considered in this category, and that projects will be favorably scored only to the extent that they demonstrate that their projects exceed environmental requirements. Originally, DP&L proposed allocating 7 points to this category.

169. Not surprisingly, this issue generated substantial discussion from the parties. Some of the parties argued that too few points were allocated to environmental factors (Delaware Nature Society, DPA, Messrs. Firestone and Kempton, GD). Even potential bidders suggested that environmental factors should be more heavily weighted in the evaluation process.

170. The IC concluded that its proposed allocation of 14 points to this factor struck the appropriate balance between those seeking a heavier weighting and DP&L's original proposal, particularly in light of its recommended use of the supercategories, in which environmental impact would comprise a major part of the Favorable Characteristics grouping. The IC explained that assigning a higher value to environmental impacts would require a lower rating for factors that assess a proposed project's viability, and those factors (financeability, site control and bidder experience) are important in assessing whether the environmental benefits associated with proposed projects will actually be achieved. The IC suggested that projects be scored based

on their: (a) greenhouse gas emissions; (b) mercury and EPA criteria pollutants such as NOx, SO2, particulate matter and ozone; (c) water impacts (including water usage and discharge); (d) land usage; (e) wildlife impacts and (f) waste disposal. These criteria would be assessed on the basis of high, medium or low/no impact. The IC noted that DP&L had proposed using specific quantifiable standards such as emissions per MWH, and stated that to the extent a scalable metric could be readily applied, it would support the use of more quantifiable point allocations.

171. The IC elaborated that as part of the evaluation, direct effects benefiting Delaware would be considered for each of the above items. As an example, the IC stated that if a proposed project would also lead to a commitment to operate another facility with high emissions less frequently, the resulting committed environmental impacts would be considered in the scoring. The IC was not suggesting a generalized analysis of the impact on emissions from other generating units, but rather a direct tie between emissions from the proposed plant and a commitment to reduce emissions from another unit(s). The IC recommended that weightings be assigned to the issues of greatest importance; thus, the IC recommended that issues (a) and (b) receive 4 points, and the remaining four issues receive 1 ½ points each. The points would be assigned on the impact per MWh expected to be produced. Finally, the IC opined that a systematic quantification of *all* environmental impacts was not necessary to provide appropriate weight to the environmental considerations pertinent to the bid evaluation, nor would it be practical to incorporate such a quantification within the limited time available.

172. We agree with and approve the IC's recommendations in this regard, with one exception to be discussed *infra*. While we are sympathetic to the concerns regarding environmental factors expressed by many of the participants, we believe that assigning 14 points directly to the environmental impact factor, along with the considerations of environmental

effects that will be part of the evaluation of other factors (such as price stability and fuel diversity), will sufficiently address environmental concerns as required by the EURCSA. The appropriate weighting of factors is a matter of judgment, on which reasonable people can (and do) disagree. In the end, it is an attempt to balance a host of competing issues, and we believe the IC's report does exactly that. We also note that points will not be awarded for compliance with regulatory programs designed to reduce emissions that are already required; rather, points will be given based on projected environmental impacts. (Unanimous).

173. However, we do not agree that projects should be awarded points for reducing existing emissions. We believe doping so would inappropriately favor existing generators in Delaware, and may reward generators for not having invested in pollution control equipment prior to submitting bids in this solicitation. Furthermore, while we believe that reducing existing emissions is laudable and worthy, the EURCSA specifically states that it is concerned with *new* generation in Delaware. By definition, reducing existing emissions at an existing plant from an existing unit cannot be "new" generation. It may be something that we could consider in the supercategory evaluation, but it is not something for which we believe points should specifically be awarded. (Unanimous).

174. ***Operation Date and Its Certainty.*** The proposed RFP assigned four points to this factor. More points will be awarded for projects that will be in-service sooner. The IC stated that earlier in-service dates appeared to further the EURCSA's purposes, although it did not specifically mention this criterion. The IC, however, recommended reducing the available points to 3 in light of the greater number of points being allocated to environmental factors, noting that this change should not be significant given the other factors considering a project's viability.

The IC finally recommended awarding one point (up to a maximum of 3) for every year before 2013 that the project could reasonably be expected to be in service.

175. We note than none of the participants objected to the IC's recommendation. We find it reasonable and approve it. (Unanimous).

176. ***Reliability of Technology and Innovation.*** The proposed RFP assigned 5 points to this factor. The RFP provided that projects would be judged on the technical maturity of the generating technology proposed, and that maximum points would be awarded to the technologies that had achieved the target EAFs specified by the bidder over at least 3 years of commercial operation. The RFP further stated that DP&L would favor projects using innovative technology (i.e., coal gasification) based on the performance guarantees offered by the bidder.

177. SCS expressed concern that the RFP assigned minimum points to new technology and maximum points to conventional technology. It noted that a coal gasification project would not meet DP&L's 3-year standard. NRG and Bluewater made similar comments, noting the potential conflict between pursuit of innovative technology and DP&L's concerns with project performance and availability. NRG proposed that coal gasification and solar photovoltaic projects receive 5 points; offshore wind and biomass using poultry waste receive 4; fuel cells, on-shore wind industrial cogeneration and other forms of biomass receive 3, coal plants using supercritical steam cycles with full post-combustion pollution controls receive 2, and natural gas and sub-critical coal fired steam units receive one.

178. The IC believed that the pursuit of innovative technology should not occur to the exclusion of projects that have a reasonable likelihood of generating electricity. The IC agreed that assigning 5 points to this factor was reasonable. The IC also agreed with DP&L's efforts to balance reliability and innovation, but recommended a more defined allocation for the two

criteria. Specifically, the IC recommended that 3 of the 5 points be allocated for innovation and 2 points be allocated for reliability. In the IC's view, the RFP defined reliability too narrowly, noting that while a technology with a strong commercial track record should score better than one with no track record, a technology with some track record and strong performance guarantees should also be given consideration in the scoring.

179. We agree with and approve the IC's recommendation. We acknowledge the EURCSA's directive to give serious consideration to new and innovative technologies, but we also have to remember that in the end we need to supply power to customers. The most innovative technology is of no use if it cannot generate the power needed to serve customers. Thus, we agree that reliability should be a consideration in the assessment of the bids. We disagree with NRG's proposed allocation of the points for this factor, as it addresses the innovativeness of the technology to the exclusion of the reliability of the technology. (Unanimous).

180 ***Fuel Diversity.*** DP&L proposed assigning 7 points to fuel diversity. It specified a preference for renewable resources and facilities that use solid fuel, as well as for projects that use diverse fuel sources. It further noted that this factor is already incorporated in the price stability evaluation.

181. Bluewater questioned the basis for preferring solid over liquid fuel and inquired whether a wind project would lose points under the proposed RFP language. Bluewater suggested that points should be awarded based on increasing the diversity of fuel used and not depend on whether the facility uses multiple types of fuel.

182. The IC partially agreed with Bluewater. It believed the preference for renewable and solid fuels was reasonable because SOS costs are related to PJM market prices (at least

forward market prices) which, in turn, are driven primarily by volatile natural gas prices. Since aspects of this factor were captured in the price stability scoring, the IC recommended reducing the available points from 7 to 3 (with the other 4 going to environmental impact). The IC did not disagree with including the use of multiple fuels in this category, but recommended that single fuel-source projects such as wind, which add diversity and reduced volatility to the power supply mix, should be given the most weight. The IC specifically noted that it was *not* suggesting an analysis of the makeup of the Delaware SOS power supply, as that would be an "impossible and non-productive task."

183. We agree with and approve the IC's recommendations on this issue. We believe that Bluewater's concerns are addressed by noting that single fuel-source projects that add diversity and reduce price volatility will be given the greatest weight in the scoring for this category. (Unanimous).

184. ***Site Development.*** DP&L assigned 5 points to this factor. The RFP description focused on site control and feasibility, including permitting, the use of brownfield or industrial locations, and certain socioeconomic issues. NRG observed that the EURCSA specifically favors the use of brownfield or existing industrial sites, and offered the following detailed criteria for the factor: permitting, site control, ability to satisfy zoning requirements, and siting feasibility for the project, including fuel delivery to transmission infrastructure.

185. The IC agreed that this factor should receive 5 points in the scoring system. It further recommended that permitting be considered as part of the siting factor, and that DP&L should request bidders to provide a permitting plan for the site that would be reviewed for its level of development and reasonableness.

186. No party took issue with the IC's recommendations. We agree with them and approve them. (Unanimous).

187. ***Bidder Experience, Safety & Staffing.*** DP&L assigned 5 points to this factor. It seeks the qualifications of key personnel and the bidder's overall experience on the functions needed to complete and operate a project; information regarding a bidder's track record; and plans for safety. Bluewater briefly concurred that safety is important and encouraged a review of the entire project based on OSHA or comparable metrics.

188. The IC agreed that a bidder's experience was highly relevant to a proposed project's viability, and that the credentials of the personnel assigned to the project was a key component for assessing this factor. It further agreed that 5 points was reasonable for this factor. The IC did not recommend a detailed supply chain safety assessment.

189. We agree with and approve the IC's recommendation on this factor. In this regard, we observe that five points is reasonable in combination with the other factors addressing the bidders' ability to complete their proposals and the "Viability" supercategory. (Unanimous).

190. ***Financial Plan.*** The proposed RFP assigned 5 points to project financeability. This assessment would include evidence of commitments from financial institutions and a financial plan for project-financed development. For corporate financing, the bidder would have to demonstrate its financial strength and appropriate financial relationships to obtain the necessary capital.

191. NRG stated that the term "financial plan" should emphasize the project's financeability, rather than whether a defined plan is already in place. It noted that financing commitments are generally not put into place until a PPA is signed, and so NRG recommended that bidders be required to provide letters of intent or support in lieu of definitive commitments.

192. The IC agreed that this factor should receive 5 points. It further agreed with NRG that project financeability should be the focus, and recommended renaming the factor “Project Financeability” and changing the description to reflect the way in which projects may be financed. While a demonstration that a bidder has a reasonable plan and an ability to finance its project is a threshold requirement, the major difference with this factor is that the threshold requirement is a minimum hurdle for all bidders, whereas at the review stage this evaluation criterion assesses the relative strength of the bidder’s financial plan and capabilities.

193. We agree with and approve the IC’s recommendation. Although the EURCSA does not explicitly identify this factor, it is, as the IC points out, fundamental to determining the realistic chances that a project will actually be completed. The EURCSA is designed to produce *operating*, not abstract, projects that will further its goals. (Unanimous).

194. ***Contract Terms.*** DP&L proposes to award 2 points based on bids having the fewest and least substantive changes to the standard PPA. At the same time, it provided a number of terms that were non-negotiable from its perspective. Although no participants provided any substantive comments on this issue, the IC was not satisfied with the description. If the proposed changes are reasonable, the IC believed that they should not be viewed unfavorably. Similarly, if there are few proposed changes but they are unreasonable, DP&L should be under no obligation to accept them and the contract will be at risk of not being executed if the bidder is unwilling to change its position. Thus, the IC recommended a clear statement that proposals will be judged on the reasonableness of the requested changes, including the impact of the proposed changes on ratepayers’ interests and the complexity and cost required to resolve them. The IC also recommended reducing the available points for this factor from 2 to 1, with the other point going to the Exposure evaluation factor.

195. We agree with and approve the IC's recommendations on this issue. We think that the IC's explanations are logical and more appropriate in the evaluative process than simply adding up the number of changes that a bidder proposes to make to the standard PPA. It is not the quantity of the changes that are important, but rather the quality. (Unanimous).

K. Term Sheet Conditions

1. Milestones/Liquidated Damages/Pre-Operational Termination Rights and Consequences

196. DP&L proposed that the permitting milestone be set 18 months after the "Effective Date." At this point, DP&L would permit a seller that has made all "commercially reasonable efforts" to obtain permits but which has been unable to do so the right to terminate the PPA. Upon such termination, DP&L would retain \$50/kW from the Developmental Security as Liquidated Damages, and would return the remaining \$50/kW. If the seller requests a six-month extension, DP&L will grant the extension if the seller agrees to pay the full \$100/kW to DP&L if it cannot obtain all required permits within that six-month period.

197. For other milestones after the "Permitting Completion Deadline," but prior to the Initial Delivery Date (e.g., financing, notice to proceed on the EPC contract, delivery of generators to the site, energization of project), if such milestones are not met within 60 days of the deadline for reasons other than force majeure, DP&L proposed that an Event of Default would arise. In this case, DP&L would have the right to terminate the PPA and retain the full amount of the Development Period Security as Liquidated Damages. DP&L explained that it would grant extensions in the Guaranteed Delivery Date of up to 12 months due to force majeure delays, and would provide an additional 12-month delay provided that the seller paid Delay Damages during that 12-month period. After all allowed delays, DP&L proposed that it could elect to terminate the PPA and receive a Termination Fee based on \$100/kW, in addition to the

Delay Damages. DP&L also proposed that failure to meet milestones during the construction period would result in the seller forfeiting certain amounts of security (which were not specified in the term sheet). DP&L would require a seller to replenish any security withdrawn (an "evergreen" provision). As for DP&L's own defaults, DP&L proposed to pay a termination payment limited to $50/kW; however, it stated that it would accept a provision for the recovery of all direct damages if the provisions were bilaterally imposed on both parties. It claimed its proposed $50/kW Liquidated Damages provision for its own default would not impede financing, and offered to make up any shortfall between Liquidated Damages and the amount of construction draws (presumably at the date of termination).

198. DP&L expressed its willingness to work with sellers in establishing milestones that worked backwards from the Guaranteed Initial Delivery Date, which would be a fixed duration selected by the seller.

199. NRG argued that the permitting period should be at least 24 months with force majeure extensions. Moreover, other than the permitting milestone, the only milestones should be financing and commercial operation. NRG further contended that the limitation of $50/kW for a DP&L pre-Initial Delivery Date default would likely make a project unfinanceable. NRG asserted that the correct measure of damages should be the recovery of the seller's expenses plus a breakage or termination fee. Finally, NRG observed that the RFP did not appear to require a DP&L affiliate to post security.

200. Bluewater suggested a 36-month period for obtaining the necessary permits. It suggested that in the event of a failure to obtain permits, DP&L would have a right to terminate the PPA but Liquidated Damages should be limited to $10/kW. Bluewater agreed with DP&L's proposal to grant a six-month extension of the permitting milestone, but the added exposure

should result in a total Liquidated Damages amount of $15/kW for any subsequent permit failure.

201. The IC noted that in its experience, setting fixed permitting and other milestones without regard to the nature and location of a particular project was "unrealistic." The IC recommended that bidders be allowed to bid milestone dates consistent with the schedule appropriate for their projects, although the overall schedule would have to come within the "not later than" deadlines in the RFP, accounting for the possibility of allowed extensions of the Guaranteed Initial Delivery Date. The IC agreed with DP&L's proposal that the Guaranteed Initial Delivery Date should be subject to a maximum 12-month force majeure extension, and that the Guaranteed Initial Delivery Date should be subject to a further maximum 12-month delay during which Delay Damages would be payable.

202. The IC characterized DP&L's proposal to limit its own damages to $50/kW during the pre-Initial Delivery Date portion of the PPA as "unworkable." The IC stated that "[I]t is conventional wisdom that damage limitations make financing entities unwilling to risk amounts of capital which may be significantly in excess of the damage recovery. Therefore, common industry practice provides that if the Buyer defaults after the commencement of construction, the Buyer should pay all direct damages as required by law." The IC observed that if the default occurs early in the PPA, benefit of the bargain damages are not always necessary, provided that the non-defaulting party is fully compensated for its losses. Here, the IC stated that DP&L's damages resulting from its default early in the process – i.e., before the commencement of construction - could be limited to reimbursement of the seller's costs plus a breakage fee. The breakage fee could be set at an appropriate level such as $10/kW, or be an amount based on a number of formula proposed by the bidder. The IC stated that after construction had

commenced, imposing limitations on recovery of damages for sellers with respect to new generation was at odds with standard industry practice, would create major financing problems, and did not account for the fact that the seller will be investing hundreds of millions of dollars in new capital to perform the contract.

203. We agree with and approve the IC's recommendations. We believe that DP&L's attempt to limit its damages will adversely affect a bidder's ability to secure financing. As we have repeatedly stated, our goal in this process is to encourage the maximum number of bidders to submit proposals. That goal will be thwarted if bidders do not bid because an onerous RFP provision precludes them from obtaining the necessary financing. We also believe that milestones should not be established ahead of time, but should be established relative to the project being bid. Thus, we agree with the IC that the bidders should submit a schedule of milestones with their bids, as long as the overall schedule is consistent with the RFP's "not later than" date. (Unanimous).

2. Delay Damages.

204. DP&L proposed that for each day of delay past the Guaranteed Initial Delivery Date, the seller shall pay $0.2333/kW per day ($7/kW per month) in Liquidated Damages, up to a maximum of $85.15/kW. Such damages would not apply to a delay caused by force majeure. DP&L also indicated that failure to meet milestone dates during the construction period may result in forfeitures of specified amounts of security. As with other Delay Damages, any security withdrawn to pay these construction period damages would be required to be replenished.

205. The IC stated that in its experience, Delay Damages were a conventional PPA provision to compensate buyers for the effects of delay and to provide sellers with relief from termination where progress is occurring but not at the pace originally hoped for. The IC

endorsed the concept of Delay Damages because delays do have consequences to buyers and sellers often need some relief in schedules established at the beginning of a project. The IC believed that the amount of Delay Damages suggested here was on the high side, but not unusually so, and as such was not commercially unreasonable.

206. We agree with and approve the IC's recommendations. Although some parties complained that the amount of delay damages was too high, none asserted that the amount was commercially unreasonable. We agree with the IC that delays have consequences to buyers and that sellers sometimes need extensions. Those extensions should not be given for free, however. Given DP&L's size and the fact that it is its customers that may be harmed by a seller's failure to deliver its project on the schedule that it proposed, we believe that the Delay Damages proposed by DP&L are reasonable. (Unanimous).

3. <u>Initial Delivery Date Requirements.</u>

207. DP&L proposed that in order for a project to achieve "Commercial Operation," the seller must satisfy 95% of the Contract Capacity. The seller also must demonstrate other items to DP&L's satisfaction, such as fuel supply, transmission service agreements and available allowances and offsets. DP&L asserts that it requires certainty in the amount of capacity contracted; otherwise, it would be forced to oversubscribe for capacity if a standard less than 95% is allowed. DP&L also objected to the IC's deletion of the condition to the Initial Delivery Date that required bidders to hold all emission allowances, credits and offsets to the extent required to operate at the maximum capacity bid.

208. None of the participants commented on these requirements.

209. The IC stated that for financing purposes, the seller's ability to meet realistic requirements for commercial operation was critical. Based on industry practice and the fact that

termination consequences flow from failures to achieve deadlines for commercial operation, the IC recommended that the 95% standard be relaxed for newer technologies. Bidders proposing such technologies should be able to bid initial percentages and standards for meeting the Initial Delivery Date that are supported by emerging industry standards. This is because for such technologies, a 95% requirement may not be consistent with market realities. Because the risk of overly strict pre-conditions to the Initial Delivery Date will stifle participation in the bidding, the IC recommended that bidders with innovative technologies be allowed to bid lower numbers based on a reasonable time period and expected production. The IC explained that it had deleted the requirement that the seller have all emission allowances, etc. because it was too vague. It noted that a seller may need to acquire allowances and the necessary amount would be based on actual production. The IC indicated that it would support such a requirement if it were based on a reasonable time period and expected production.

210. We agree with and approve the IC's recommendations. As we have stated numerous times throughout our deliberations and in this Order, we do not want to stifle bidders at the beginning by erecting unnecessary barriers to participation in the bidding process. Once the bids have been received, they will be evaluated, and these issues can be hashed out then. (Unanimous).

4. <u>Events of Default/Remedies</u>

211. This proposal addressed remedies upon a seller's default on a firm energy contract. As a result of our decision with respect to the bidding of firm energy contracts versus unit contingent contracts, this proposal is not longer applicable.

5. <u>Set-Off</u>

212. DP&L proposed that upon default, the non-defaulting party have the right to set off against any amounts owed to the defaulting party or any of its affiliates under the PPA or otherwise any amounts payable by the defaulting party to the non-defaulting party or any of its affiliate under the PPA or otherwise. NRG contended that set-off rights against affiliates are unacceptable and should be eliminated because they do not work in the project finance context. DP&L disagreed with NRG that lenders object to set-offs in the context of how DP&L is using the term: "allowing a non-defaulting party to set off amounts owed to a defaulting party."

213. The IC stated that in its experience, affiliate set off rights impair a seller's ability to obtain financing and should be eliminated for that reason alone. Thus, the IC recommended that any amounts payable by a defaulting party to a non-defaulting party's affiliates should *not* be offset against amounts payable to the defaulting party by the non-defaulting party under the PPA. As an example, the IC stated that if the seller is in default, but is owed amounts for outstanding invoices for power actually delivered, the buyer should not offset against these power bills due amounts due from the seller to an affiliate of the buyer under some other arrangement between the seller and any such affiliate of the buyer.

214. We agree with and approve the IC's recommendations for the reasons stated therein. We do not believe it is appropriate for the buyer to be able to set off against a defaulting seller amounts due to that seller from an affiliate of the buyer under a separate contractual arrangement. We can understand how this provision would negatively affect a seller's ability to obtain financing. (Unanimous).

6. <u>Change in Law</u>

215. DP&L proposed that the seller bear all the risks of complying with applicable requirements of law, PJM and FERC, whether imposed pursuant to existing law or pursuant to

changes enacted or implemented during the term of the PPA, including, without limitation, changes in environmental laws. DP&L took the position that a present or future carbon tax could be treated either as a seller's responsibility or as a pass-through energy cost, subject to DP&L's ability to recover that additional cost in rates. In any event, no additional costs should be imposed on DP&L. DP&L claimed that present Commission policy supported its position. DP&L also asserted that reopener clauses might be appropriate in commercial contracts that are freely negotiated, but the PPA was not such a contract and thus the two situations were on "decidedly unequal" footing.

216. NRG contended that future environmental compliance costs should be borne equitably by the parties. It further objected to limiting a pass-through to a Btu or carbon tax, claiming that that limitation was contrary to the EURCSA. It further contended that until there is such a tax, it does not know what that amount could be and would not be able to price it into any bid. Therefore, NRG argued that it should be able to pass the cost through to the buyer or re-open negotiations with the buyer on this issue.

217. Messrs. Firestone and Kempton oppose any pass-through to customers of Btu or carbon taxes. GD and the NRDC argued that the provision to pass through future carbon taxes frustrated the legislative goals of securing price stability and reducing the environmental impact and weakened the bids of renewable power producers, who offer price stability in that they would not be subject to such taxes.

218. The IC stated that standard industry practice with respect to long-term PPAs makes sellers responsible for future compliance costs that are not in the nature of a tax; however, with respect to future compliance costs in the form of a carbon or Btu tax of general applicability, it is common for those costs to be shifted away from the seller. The IC

recommended providing bidders with two options. First, a bidder could assume the change-in-law risk in its entirety and its bid would be so treated in the economic evaluation. Alternatively, a bidder would assume compliance costs other than those not in the nature of a tax, and, in the event of a future carbon or Btu tax of general applicability, a bidder could seek only to recover the amount of such tax attributable to the average cost that would be assessed on generators in the relevant market based on average emissions. Specifically, the IC recommended limiting the seller's ability to recover costs imposed on it by such taxes only to the extent of the amount of tax per MWh attributable to the average level of emissions from all facilities in the PJM Classic market. In this manner, a bidder would accept the financial risk associated with a Btu or carbon tax that it would contribute to greenhouse gas emissions to an extent greater than the market norm. This is reasonable from an economic standpoint because market prices would be expected to rise based on average emissions and it is reasonable for a seller to be at risk for the excess amount. The IC noted that a bidder that takes the entire risk and a bidder with no emissions will score better in the price and price stability categories, all other things being equal.

219. The IC opposed NRG's argument for a broader price adjustment provision associated with environmental laws or regulations that may require capital expenditures or increased operating costs in order to comply. The IC took the position that it was reasonable for a seller under a long-term contract to assume the risk and incorporate that risk allocation in its bid. The risk could also be addressed in connection with the contract term (10 to 25 years). Finally, the IC found that NRG's proposal was too open-ended and it would be difficult to structure and implement the type of contract provision NRG advocated.

220. We agree with and approve the IC's recommendations, and in addition further find that any such taxes imposed and paid by DP&L as required under contract provisions will be

allowed for recovery. We note that not all changes of law will result in additional payments that DP&L will be contractually obligated to make and, hence, will not result in a pass-through to SOS customers. The seller will be primarily responsible for such costs, subject to the one exception that the IC's report identified. (Unanimous).

7. Dispute Resolution

221. DP&L proposed that all disputes regarding the RFP process and the PPA be referred to the Commission for decision. DP&L contended that the Commission is charged with protecting the public interest and is the most knowledgeable party to address contract issues. Furthermore, the Commission would offer "one-stop treatment," resolving the problem and if PPA costs increased as a result, making a decision on the related increase at the same time. NRG argued that the Commission should not be stipulated as the ultimate decisionmaker for disputes between the parties. In NRG's view, that would create the impression of an advantage for the buyer and would make it difficult for the bidder to obtain financing for the project on standard market terms.

222. The IC stated that industry practice was not uniform on this issue. Generally, disagreements about long-term PPAs are resolved by arbitration or litigation or some combination of the two. The IC found it "rare" for a state regulatory body to resolve PPA or RFP disputes between the parties. Because of its responsibility to protect ratepayer interests, the independent power industry may not view the Commission as completely neutral in resolving contractual disputes that could result in higher power costs to ratepayers. The IC concluded that the nexus between rate setting and dispute resolution was problematic and beyond the normal scope of the Commission's responsibilities.

223. On this issue, we agree with DP&L's position. We understand the IC's position, but in truth this is a new area of responsibility for the Commission, so to say that it is beyond our normal responsibilities only goes so far. We have resolved disputes between parties to contracts in other matters, and we see no reason why we cannot do so here. (1-0, Energy Office representative Cherry abstaining).

8. <u>Miscellaneous Issues (Change in Control)</u>

224. DP&L proposed that the seller should pay DP&L's reasonable costs associated with review, negotiation, execution and delivery of any documents relating to consent to assignment, including attorneys fees. DP&L further proposed that the seller should pay all expenses (including attorneys fees) that DP&L incurs after any of seller's obligations are not paid or performed when they are due, after a default or an Event of Default occurs, or in exercising or enforcing or consulting with its counsel regarding any of its rights under the PPA or other law.

225. NRG argued that a seller should not be required to pay DP&L's legal costs to effectuate an assignment; that the force majeure clause should be revised to make it more equitable; and the assignment clause should be revised to avoid any implication that a future change of control of the seller required DP&L's approval. DP&L contended that the continuity of the identity of the seller is critical to the PPA and that it is wholly consistent with industry standards to require the buyer's consent if control is transferred.

226. The IC disagreed that there was a clear industry standard with respect to change in control, but was agreeable to DP&L including in the PPA reasonable change of control language to satisfy its concerns as long as that provision was not non-negotiable. As for the language regarding consents to financing assignments, DP&L suggested offering a form of consent. The

IC found that this was a common and workable approach, and that PPA buyers frequently prepared consent forms acceptable to financing entities.

227. The IC opposed DP&L's proposed reimbursement language as overly broad in scope and outside conventional practice. It recommended eliminating the language requiring the seller to pay all of DP&L's expenses when DP&L consults its counsel with respect to any of its rights. The IC recommended that the other expense reimbursement language and the force majeure language required tightening up to avoid covering normal transactional costs. The IC reviewed DP&L's proposed revisions and found them acceptable.

228. We agree with and approve the IC's recommendations. The change in control provision is a provision that is included in thousands of commercial contracts, and it simply gives DP&L the right to withhold its approval of a transfer of the contract. However, DP&L's discretion in this regard is not unfettered; rather, the approval must not be unreasonably withheld. We believe with this revision, the provision is acceptable. We also observe that DP&L's revisions to its expense reimbursement and force majeure language are acceptable to the IC. As a result, we accept that language. (Unanimous).

III. <u>ORDER</u>

AND NOW, this 31st day of October, 2006, IT IS HEREBY ORDERED:

1. That the Independent Consultant's Report (attached hereto as Exhibit A) is hereby adopted and approved, except as follows:

    (a) The Commission will exercise jurisdiction over any disputes arising from the RFP process or out of any PPA executed between DP&L and a Seller; and

(b) In determining a bidder's score under the environmental non-price factor evaluation, there will be no consideration given to emissions reductions from a generating unit other than one that is being bid in assessing the emissions from the bid unit.

2. That the Commission reserves the jurisdiction and authority to enter such further Orders in this docket as may be deemed necessary or appropriate.

BY ORDER OF THE COMMISSION
AND THE ENERGY OFFICE:

____
Arnetta R. McRae, Chair
On Behalf of the Commission

____
Philip J. Cherry, Director of Policy & Planning,
Delaware Department of Natural Resources &
Environmental Control
On Behalf of the Delaware Energy Office

ATTEST:

____
Secretary
174281.1